

A Decision Making Tool to Assist in Choosing between Polymer flooding and Infill Well Drilling

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ABSTRACT

Oil companies propose polymer flooding techniques, but oftentimes find it difficult to convince asset teams to implement these. This is because it is much easier to estimate the return on investment from an infill well drilling programme, and the return is much quicker. On the other hand, there may be a delay of years before increased oil recovery is observed following implementation of polymer flooding process, and indeed, it may be difficult to ascertain just how much incremental oil has been recovered.

The work developed in this thesis involved setting up a range of polymer flooding scenarios, performing analysis using both very detailed reservoir simulation calculations with a range of sensitivities, and also economic calculations, again testing a range of parameters, to ensure that a full range of possible outcomes is evaluated, and then making a comparison with infill drilling to maximise the value of mature assets.

The method was first applied to a synthetic scenario with constant economic parameters, and was then applied and tested with varied operational and economic parameters. These sensitivity calculations have been performed by developing a computer program, coded in Java. Monte Carlo Simulation (MCS) is then performed to generate statistics from this method, and test economic uncertainties and the risks associated with implementation of polymer flooding.

The method was then applied to a real field system where the choice of infill well drilling had previously been made by the operating company, to test the robustness of the analysis using polymer flooding against a conventional decision making process for which there is historical data. Finally, the approach was then used in an offshore field which has been undergoing waterflooding, but where the choice for further field development has yet to be made, with the operator considering polymer flooding as an alternative (or in addition) to infill well drilling.

The thesis discusses the implications of using this newly developed methodology in identifying the risk of failure and in assisting in making an optimal choice based on technical and economic considerations in a fully integrated manner.

DEDICATION

I present this thesis to those who have set a good example to me throughout the whole of my life; my beloved parents who have taught me that knowledge is a light, which clears the darkness of minds.

Also, to those who support my journey with patience, towards this achievement; my beloved wife and my children Malik, Moayad and Lamar.

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LIST OF PUBLICATIONS

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- Alusta, G., Mackay, E.J., Fennema, J., Armih, K., and Collins, I.R.: “EOR vs. Infill Well Drilling: Sensitivity to Operational and Economic Parameters” paper SPE 150454 presented at the SPE North Africa Technology Conference and Exhibition, Cairo, Egypt, 20-22 February 2012.
- Alusta, G., Mackay, E.J., Fennema, J., Armih, K., and Collins, I.R.: “EOR vs. Infill Well Drilling: Field application of new decision making technique” SPE 163298, presented at the SPE Kuwait International Petroleum Conference and Exhibition, Kuwait, 12-14 December 2012.
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NOMENCLATURE

| | | |
|--------------|---|-------------------|
| <i>CAPEX</i> | <i>Capital expenditure</i> | <i>\$ Million</i> |
| <i>CDCF</i> | <i>Cumulative discount cash flow</i> | <i>\$ Million</i> |
| <i>CICE</i> | <i>Cumulative incremental capital expenditure</i> | <i>\$ Million</i> |
| <i>CICF</i> | <i>Cumulative incremental cash flow</i> | <i>\$ Million</i> |
| <i>CIOE</i> | <i>Cumulative incremental operating expenditure</i> | <i>\$ Million</i> |
| <i>CIWCE</i> | <i>Cumulative incremental well capital expenditure</i> | <i>\$ Million</i> |
| <i>COIOE</i> | <i>Cumulative other incremental operating expenditure</i> | <i>\$ Million</i> |
| <i>DCF</i> | <i>Discount cash flow</i> | <i>\$ Million</i> |
| <i>DR</i> | <i>Discount rate</i> | |
| <i>FOPT</i> | <i>Field oil production total</i> | <i>bbl</i> |
| <i>FWIT</i> | <i>Field water injection total</i> | <i>bbl</i> |
| <i>FWPT</i> | <i>Field water production total</i> | <i>bbl</i> |
| <i>i</i> | <i>Discount rate</i> | <i>%</i> |
| <i>ICE</i> | <i>Incremental capital expenditure</i> | <i>\$ Million</i> |
| <i>ICF</i> | <i>Incremental cash flow</i> | <i>\$ Million</i> |
| <i>IOE</i> | <i>Incremental operating expenditure</i> | <i>\$/bbl</i> |
| <i>IOP</i> | <i>Incremental oil production</i> | <i>\$ Million</i> |
| <i>IOPE</i> | <i>Incremental oil production expenditure</i> | <i>\$ Million</i> |
| <i>IPIC</i> | <i>Incremental polymer injection cost</i> | <i>\$/bbl</i> |
| <i>IPPC</i> | <i>Incremental polymer production cost</i> | <i>\$/bbl</i> |
| <i>IWCE</i> | <i>Incremental well capital expenditure</i> | <i>\$ Million</i> |
| <i>IWDCE</i> | <i>Incremental well drilling and completion expenditure</i> | <i>\$ Million</i> |
| <i>IWOE</i> | <i>Incremental well operating expenditure</i> | <i>\$ Million</i> |
| <i>IWP</i> | <i>Incremental water production</i> | <i>\$ Million</i> |
| <i>IWPE</i> | <i>Incremental water production expenditure</i> | <i>\$ Million</i> |
| <i>IWI</i> | <i>Incremental water injection</i> | <i>\$ Million</i> |
| <i>IWIE</i> | <i>Incremental water injection expenditure</i> | <i>\$ Million</i> |
| <i>MCO</i> | <i>Maximum capital outlay</i> | <i>\$ Million</i> |
| <i>NPV</i> | <i>Net present value</i> | <i>\$ Million</i> |
| <i>NPVI</i> | <i>Net present value index</i> | |
| <i>OPEX</i> | <i>Operating expenditure</i> | <i>\$ Million</i> |

| | | |
|---------------------------------|--|-------------------|
| <i>OIOE</i> | <i>Other incremental operating expenditure</i> | <i>\$ Million</i> |
| <i>PPE</i> | <i>Polymer purchasing Expenditure</i> | <i>\$ Million</i> |
| <i>PC</i> | <i>Polymer concentration</i> | <i>ppm</i> |
| <i>PC</i> | <i>Polymer cost</i> | <i>\$/lb</i> |
| <i>WF</i> | <i>Water flooding</i> | |
| <i>WIC</i> | <i>Water injection cost</i> | <i>\$/bbl</i> |
| <i>WCIT</i> | <i>Field polymer injection total</i> | <i>mm lb</i> |
| <i>WCPT</i> | <i>Field polymer production total</i> | <i>mm lb</i> |
| <i>WCT</i> | <i>Water cut</i> | <i>%</i> |
| <i>WPC</i> | <i>Water production cost</i> | <i>\$/bbl</i> |
| $\overline{\overline{S_{wbt}}}$ | The volume averaged water saturation behind the flood front | |
| f_{ws} | Water cut at surface | |
| S_{wbt} | The average water saturation at breakthrough, fraction | |
| S_{wf} | Water saturation at the flood front | |
| f_{wbt} | Producing water cut at producing well breakthrough, fraction | |
| $N_{pdpt} - PV$ | Dimensionless cumulative oil production (in pore volumes) | |
| M_s | Shock front mobility ratio | |
| M | Mobility ratio | |

CHAPTER 1: INTRODUCTION

1.1 Introduction

Mature water flooding projects may offer excellent opportunities for field life extension using enhanced oil recovery (EOR) techniques, such as polymer injection, as the uncertainties associated with reservoir connectivity and injection potential are already significantly reduced by years of operation and data gathering Abu-Shiekah et al. (2012).

Traditional primary and secondary production methods typically recover between one and two thirds of the original oil in place (OOIP), leaving much behind. The reasons for this are technical and economic, and are not difficult to understand. During primary depletion, there is often not enough energy in the system to lift all the oil. If fluids are injected to provide pressure support and sweep the oil towards the production wells, then the injected fluids may leave oil behind at all length scales – from pore scale (residual oil) to reservoir scale (bypassed attic or basement oil, say). In addition, during the lifecycle of a well, there is always a point at which the cost of producing an additional barrel of oil is higher than the price the market will pay for that barrel. Under normal circumstances, wells are abandoned with as much as 70% of the oil left in the ground Lake et al. (1992).

At present, the world-wide production statistics indicate that the ultimate recovery from light and medium gravity oils by conventional (primary/secondary) recovery methods is around 25-35 % of the OOIP, while from heavy oil deposits, on average only 10 % OOIP is recoverable. Hence a substantial fraction of oil in place is non-recoverable by conventional methods, and these remaining reserves may become the target for EOR to increase the recovery fraction Zekri et al. (2000).

Infill drilling is a means of improving sweep efficiency by increasing the number of wells in an area. Well spacing is reduced to provide access to unswept parts of a field. Modifications to well patterns and the increase in well density can change sweep patterns and increase sweep efficiency, particularly in heterogeneous reservoirs. Infill

drilling can improve recovery efficiency, although it also it can be more expensive than optimising fluid displacement process Fanchi (2006).

Drilling of infill wells usually also *accelerates* the production of oil from a reservoir because oil bypassed during water flooding with large spacing patterns can be produced as soon as the infill well is completed. This oil may have been unswept because the injected water does not enter or flow in a particular zone of the reservoir due to low permeability, clay sensitivity, gravitational effect and/ or wellbore blockage. Infill well drilling may be used in conjunction with EOR techniques Holm (1980).

Infill wells are drilled in reservoirs undergoing waterflood mainly to increase the net asset value by draining additional reserves and/or by accelerating recovery of existing reserves. A high primary recovery factor usually encourages the operator to consider water flooding, since reservoirs with large primary recovery factors also often yield strong water flood recoveries. Therefore, reservoirs with large oil-in-place and a large combined oil recovery factor (primary plus water flood) become prime candidates for infill drilling. However, some of the waterfloods in reservoirs with lower recovery factors may also offer attractive economic opportunities for infill drilling Singhal et al. (2005). Infill drilling will permit production of oil from parts of the reservoir that might be bypassed by standard low density well spacing. Well spacing is the key to solving recovery problems caused by heterogeneity. In fields that have wells of varying ages, the production characteristics of older wells should be compared with those of new wells. It is not uncommon to find wells spaced in such a way that they are in very poor communication. This results from the fact that all reservoirs are heterogeneous to some degree or other El-Feky (1987).

On the other hand, a polymer flood may be used to enhance oil recovery from a reservoir by improving reservoir sweep and reducing the amount of injection fluid needed to recover a given amount of oil. Polymer floods work by adding low concentrations of water-soluble polymers to injection water to increase the injectant viscosity. This is done to more closely match the injectant viscosity to that of the in situ oil, and thus achieve a more favourable mobility ratio and sweep efficiency Kaminsky et al. (2007).

Polymer flooding is an EOR technology that can recover more oil by the inclusion of an additional oil displacement agent (the polymer), while injecting water to maintain the reservoir pressure. By increasing the viscosity of the injected water, the polymer reduces the oil-water viscosity ratio, increases the sweep volume, and thus enhances oil recovery. Since 1975, the worldwide application of polymer flooding technology shows that the application of this technique can lead to an increase in recovery in the range 6% to 52% of OOIP. In China, polymer flooding has increased oil recovery by 10% based on the statistics from nearly 30 oilfields during the last 20 years. In 1997, China's production gain using polymer flooding reached 3.03×10^6 t, and the number is 15×10^6 t for the period 1996-2000 Zhang et al. (2010).

The accuracy of the economic evaluation and revenue projection of the oil and gas industry hinges on the confidence placed on the production forecast used. Other factors, such as price regimes, facilities constraints and other socio-political issues also affect revenue projection. However in the case where all these factors are relatively stable, production forecasts remains the major determinant in the accuracy of cash flow predictions and ultimately strategic decisions for an oil and gas company Adepoju et al. (2009).

1.2 Thesis Objective and Approach

Two of the main challenges for EOR processes at the prevailing oil prices are to reduce costs and to reduce uncertainties. In the work presented in this thesis an optimization methodology, combined with an economic model, is developed and implemented for assessing the net present value of a full field development with an EOR Process This process can also be followed for an infill well drilling strategy, and the results compared.

An optimization methodology technique was developed to assist in choosing between EOR and infill well drilling by combining Reservoir Engineering and Petroleum Economics. The approach used in this project involves selecting appropriate EOR scenarios, performing reservoir simulation calculations to estimate additional oil recovery, and then making a comparison with a similar scenario, but where infill drilling has been used to maximise recovery instead, and provide these as input to an economic model. The output of the economic model will be net present value (NPV) or

some other economic parameters, such as return on investment (ROI). This approach was done for polymer flooding, but the approach could be used for other EOR techniques also.

In each case a range of parameters will be varied to investigate the impact of the associated uncertainties. Not only will the value of the various options be considered, but also the spread in outcomes possible arising from uncertainties in the system, the impact of timing, and the method of estimating technical, financial and environmental risks.

1.3 Thesis Outline

In Chapter 2, an overview of polymer flooding and economic calculations of associated EOR techniques is presented, relating the work of the other researchers in this field to the current thesis. This literature review focuses on the contributions to knowledge of the other researchers, as well as any apparent deficiencies. In particular most other work in this area has concentrated on using single values for economic variables, whereas the work in this thesis concentrates on the benefit of accounting for a range of reservoir engineering parameters and a range of economic parameters together.

In Chapter 3, the understanding of how the economic comparison should be performed is developed, since the timescales for investment and return on investment and the associated risks and uncertainties are different for EOR projects and infill well drilling. The method involves studying a range of scenarios, selecting appropriate EOR techniques and modelling the impact these techniques have on recovery, and then running calculations of the impact of various options. An economic assessment is made of the costs and risks of the various options together with expected return under a range of economic scenarios. Initially a synthetic reservoir simulation model was developed to study the impact of polymer flooding vs. waterflooding. NPV was calculated for the economic comparison between the polymer flood and infill well scenarios. (The model was designed for polymer flood calculations, but can be easily adapted to assess other EOR methods.) The cash flow for this study was determined by generating the revenues by combining the oil production profile with the oil price profile.

In Chapter 4, we investigate the impact of delaying the start of polymer flooding to identify whether it is better to start polymer flooding earlier or later in the life of the project, and to compare the polymer flooding scenario with a different scenario where infill well drilling is introduced. This was achieved by performing a range of sensitivity calculations (reservoir simulation and economic modeling), using Monte Carlo simulation to establish confidence in the method and test uncertainties on key operational parameters, using specialist analysis software. Sensitivity analysis graphs were developed to assess future engineering planning with regard to the economics of such EOR projects. These sensitivity calculations are numerous, and have been performed by developing a computer program, coded in Java. A total of 1,093,500 economic calculations were performed, based on 225 reservoir simulation calculations.

In Chapter 5, the methodology was applied to the Arbroath oil field, offshore in the North Sea, where the choice has already been made to drill infill wells, but where we test the strength of the technique against a conventional decision making process for which there is historical data. This was done by performing calculations that compare the infill well scenario chosen with a range of polymer flooding scenarios that could have been selected instead, to identify whether or not the choice to drill infill wells was indeed the optimum choice from an economic perspective.

In Chapter 6, the methodology is applied to the Schiehallion offshore oil field, where the field has been undergoing waterflood, and where the operator is considering polymer flooding as an alternative (or in addition) to infill well drilling.

In Chapter 7, the main conclusions for each part of this study, that have been drawn in the course of this study, are presented. The areas that still require future work are highlighted, along with discussion around how this methodology should be applied as a routine analysis tool.

CHAPTER 2: LITERATURE REVIEW

In the North Sea average recoveries are reported to be above 40% of initial oil in place. The Norwegian Petroleum Directorate in 2001 set a target of 50% recovery for the Norwegian sector of the North Sea and it was envisioned that EOR techniques could be used to achieve this target. However, many oil companies rely primarily on infill well drilling to increase recovery factors as their default option because with the information that they have they can target new wells to recover bypassed oil. EOR techniques involve a greater degree of uncertainty in predicating recovery factors, and therefore, risk and economic assessments are more difficult to perform Awan et al. (2008).

This thesis is going to concentrate on polymer flooding as an EOR technique to compare with infill well drilling.

Addition of polymer to injection water increases the viscosity of the water and hence reduces the mobility of the displacing fluid, increasing the microscopic sweep efficiency. Macroscopic sweep efficiency is also improved by the reduction in channelling in heterogeneous reservoirs. Initially the polymer slug is displaced primarily into the high permeability zones so the mobility in these high permeability zones is reduced disproportionately. Subsequently injected fluid will increasingly displace hydrocarbons from the low permeability zones, improving overall sweep efficiency.

Infill well drilling does not impact microscopic sweep efficiency but seeks to improve the macroscopic sweep efficiency by targeting oil that has not been swept by water. Due to gravity effects this bypassed oil is often to be found near the top of the reservoir and referred to as attic oil.

The following is a literature review that focuses on the contributions to knowledge of other researchers working on economic calculations of polymer flooding and associated EOR techniques and the various types of decision making processes they have developed.

Barua et al. (1986) described a reservoir engineering and economic tool for decision making for a chemical EOR method (in this case surfactant rather than polymer flooding, but the types of reservoir engineering input and output are similar). The economic input will be mainly the same in this thesis except that the raw material is different (polymer versus surfactant). However, in this paper all economic variables are fixed, and thus the interplay between reservoir engineering and economic uncertainties are not considered.

Gharbi (2000) developed an expert system to select an appropriate EOR process based on reservoir characteristics, input data sets to design the selected EOR technique using reservoir simulation and making sensitivities to study several key parameters to optimise the oil recovery such as polymer concentration, timing, and duration of polymer injection, etc. A real field case was used in this paper and the reservoir assumed to be produced at economic limit and is potential candidate for an EOR process.

Flow charts will be developed in this thesis work following the work of Gharbi (2000) describing the steps used for the polymer flooding project optimization. Then a range of reservoir simulation scenarios will be run to test possible recovery outcomes; these outcomes will then provide input data that will be used in the probabilistic economic evaluation tool.

Wences et al. (2001) presented an approach to guide the work of a reservoir simulation team to identify the best strategy to maximise recovery based on an economic analysis such as NPV, the calculation of mobile saturation, the optimum number of additional wells drilled and their locations, to compare with primary, secondary and an EOR process (which could be waterflooding, gas injection or WAG). The application of this method resulted in a significant reduction in both uncertainties and the number of sensitivity runs needed. NPV versus number of additional infill wells drilled was plotted as an output, which was useful, but the economic input parameters values were not included in the paper.

Gharbi (2004) presented the use of reservoir simulation to optimise recovery from a carbonate reservoir using an EOR process such as carbon dioxide (CO₂), water alternating gas (WAG) and simultaneous alternating water & gas (SWAG). In the paper, new infill wells were drilled in all areas of the reservoir where there was mobile oil and the cost of these wells were included in the economic model, along with other parameters such as oil price, OPEX, CO₂ recycle cost, CO₂ cost, royalty, taxes, inflation rates and real discount rate (the economic cost values are fixed).

Singhal et al. (2004) presented a few cases of infill well drilling performance in water flooding and miscible flood projects in the western Canadian sedimentary basin. The authors noted that sweep efficiency largely depends on areal heterogeneity in different intervals, in addition to factors such as mobility ratio, injected fluid type and flood pattern geometry. The paper helpfully explores some possible methods for estimating areal or lateral heterogeneity in water flooding and miscible flood projects, based on vertical and horizontal infill well drilling performance.

In the case described, heterogeneity depends upon the depositional environment and on subsequent diagenetic and structural events that led to the formation of dolomite, anhydrite, faulting, fracturing, etc. As a result of these events, pay zones were divided into several segregated intervals and horizontal compartments where lateral heterogeneities dominate. Heterogeneity was identified as site specific and should be individually determined. Due to the site specificity, some locations were suitable for horizontal infill wells, and others for vertical infill wells. Options should be chosen based on field data and sensitivity calculations.

While in the work in this thesis we initially consider vertical wells, this paper highlights how horizontal infill well drilling may be planned and we follow this and include horizontal wells also.

Lateral heterogeneities are critical in targeting what reserves an infill well should produce. Injected water being displaced through the reservoir will take the path of least resistance towards the new infill production wells. Thus, distribution of regions with better or poorer reservoir quality will determine areal sweep efficiency.

This means that in addition to consideration of engineering choices, such as well locations, flow rates, polymer concentration, timing, etc., the sensitivity analysis should take into account uncertainty in the reservoir description, as this may impact the location of unrecovered reserves. This type of analysis to geological uncertainty is not accounted for in this thesis, although, again the proposed economic analysis methodology can readily compare the impact of different underlying geological descriptions on the reservoir simulation outputs.

Gharbi (2005) used the same developed expert system presented in Gharbi (2000) to measure the project profitability as a decision making process based on two reservoirs that have already produced to their economic limits and were potentially candidates for surfactant/polymer and carbon dioxide CO₂ flooding, respectively. The economic model was developed using discounted cash flow (DCF) method to optimise the selected EOR process, and the author of the economic model designed it also for surfactant and polymer injection, as well as for solvent gases, such as CO₂, nitrogen, or miscible hydrocarbon gas. Fixed economic parameters were used in his model, with a fixed cost per barrel used to estimate the direct operational costs. NPV and IRR were calculated. The work in this paper presented what could be described as a standard tool.

The work in this current thesis concentrates on one EOR process, polymer flooding, but the tool should be suitable for evaluation of a range of non-thermal recovery processes, by simple alteration of some of the input parameters.

Wences et al. (2005) illustrated a process that enables the reservoir engineer to identify the optimum number of infill wells and locations, and to identify the appropriate EOR technique. The inputs include maximum flow rate, production and injection facilities, CAPEX and OPEX. The author also introduced a decision making process for both technical and economic risk analysis using Monte Carlo Simulation to generate a probabilistic model (P10, P50 and P90) of economic outputs such as NPV and IRR. In this paper also several sensitivities scenarios were made by modifying only one variable at time.

In this thesis work, the combination between the operational parameters and the economic parameters will be numerous and a computer program will have to be

developed to handle all the data. MCS will be performed to test the economic uncertainties and risk assessment associated with infill drilling and polymer flooding.

Lopez et al. (2007) described the technical and economic viability of infill well drilling before making a decision to implement a water-alternating-gas (WAG) process. Their methodology focused on maximising net present value (NPV) for various assumptions about infill well drilling, using a combination of reservoir simulation outputs and economic analysis. Infill well drilling locations were identified by considering well spacing of 300, 450 and 600 meters. In each case the authors performed an economic evaluation and used fixed values such as operational cost, cost of new wells, oil price, interest and exchange rates, and the cost of surface facilities.

Optimisation of well spacing, well flow rate, artificial lift and timing of new wells will not be considered in this study, but the method developed should cope with all such sensitivities.

Costa et al. (2008) introduced a method to quantify the impact of uncertainties in ASP flooding to improve sweep efficiency. The approach was based on using sensitivity calculations to identify the parameters that have the highest impact on recovery, and then develop risk plots which are similar to probability distributions to represent the P10, P50 and P90 cases.

This useful extension to previous work in that some of economic uncertainty is introduced. However, it is limited to three reference points (P10, P50 and P90).

The key advance in this thesis is that it will take into account the full range of operational parameters AND the full range of economic parameters in the one evaluation. (i.e. economics not just evaluated on P10, P50 and P90 scenarios).

Saputelli et al. (2008) presented a methodology to improve the likelihood of project success at all stages during the life of the field. Various approaches were used, based on economic criteria such as NPV and the efficient use of resources, to maximise recovery. The term “resources” is used by the authors to describe various inputs such as drilling, facilities, and EOR options, etc. In many cases in this work, it was found that the oil price had the greatest impact on project economics.

The decision making process during production will be affected by uncertainties in the reservoir such as wettability, initial fluids in place, rock properties, fluid PVT mobility, water cut limits, aquifer support, injectivity, micro and macroscopic recovery efficiencies, etc.).

The uncertainty associated with economic parameters (such as costs, etc.) should be included in the economic model. A probability distribution tool, such as a Monte Carlo simulation, is used to identify the impact of input variables on the economic outcomes, such as mean, standard deviations, P10, P50, and P90.

The methodology developed in this thesis is to test varied operational parameters (oil, water and polymer production and injection costs, polymer concentration, timing, etc.) and various economic parameters (oil price, polymer cost, etc) to compare polymer flooding scenarios with infill well drilling scenarios, not just based on incremental recovery, but on Net Present Value as well. Due to the large number of combined reservoir engineering and economic scenarios, Monte Carlo Simulation and analysis of large data sets and the resulting probability distributions had to be developed. The analysis of uncertainty involves measuring the degree to which input contributes to uncertainty in the output.

Alsofi et al. (2011) illustrated polymer flooding design using an optimization associated with uncertainty analysis, but factors such as cost of the production facilities, water and polymer production were not included in the economic model. Part of the benefit of polymer injection is not just increased oil recovery but also the decreased water production, and the economic model developed in the thesis will take this into account.

Beckman et al. (2011) introduced a reservoir simulation tool to investigate sweep efficiency and identify target bypassed oil. The tool derived information from a reservoir simulation model and then performed a calculation using a process of subdividing the oil in place into eight categories (based on layering) to identify where incremental oil production may come from, which intervals produce first, etc. This subdivision is a useful aid to optimise EOR. However, timing and targeting of early polymer injection into optimal zones could be carried out using reservoir simulation, as

in the work by Beckman et al. (2011) and this would feed very naturally into the economic modelling tool developed in this thesis.

In this thesis the first step is to use reservoir simulation (Eclipse 100) to identify the volume of unswept oil to improve recovery and then the reservoir simulation output will feed into the economic model to assess whether these volumes are best economically produced by infill well drilling or with non-thermal EOR technique such as polymer flooding. The work in this thesis does not look in detail at timing of recovery from one zone compared to another (although it does consider timing of overall change from waterflooding to polymer flooding).

An EOR “prefeasibility” study to identify the principal uncertainty and risk associated with EOR projects such as the geological features, oil price, cost of polymer, risk of failure in polymer supply chain, etc were described by Lefebvre et al. (2012). The paper describes 3D analytical models with different reservoir geometries that were used for a variety of EOR techniques such as polymer, surfactants, surfactant-polymer, steam injection, SAGD, in situ combustion and gas injection. Because they did not have access to experimental data for polymer flooding, the authors used polymer property data from literature. They modelled the polymer slug effect using polymer concentrations of 500, 750 and 1000 ppm.

In this work the polymer data will be derived from (Sorbie, 2000).

The same type of reservoir engineering output as was generated for the polymer flooding sensitivities by Lefebvre et al. (2012) was used in this thesis. They performed economic calculations for all recovery methods (non-thermal and thermal), but do not specify input parameters clearly. This thesis will be restricted to polymer flooding (and will specify input parameters clearly), methodology may be readily extended to other non-thermal techniques. More significant modification would be required for thermal processes. Lefebvre et al. (2012) computed water front breakthrough and oil recovery using Buckley-Leverett (1942) fractional flow theory, which is a very useful analysis technique in the original screening of recovery methods, and is very usefully adopted in the work in this thesis also.

The methodology proposed in this thesis will be applied to a synthetic model scenario to develop the method and then it will be tested and applied to real fields.

Alkhatib et al. (2012) introduced a decision making evaluation method for chemical EOR using a Least-Square Monte Carlo Method. The aim of their methodology was to reflect the effects of dynamic uncertainties in both technical and economic components.

The work was carried out for surfactant flooding during the life time of the field under various uncertainty assumptions. The reservoir engineering output was the same as will be used in the present work but the CAPEX cost of the surfactant injection was not explicitly included in the economic model.

In the present work Monte Carlo Simulation (MCS) will be performed to test economic uncertainties and the risks associated with implementation of polymer flooding versus in fill well drilling. Defining variables with a probability distribution can establish more robustly the economic value of both techniques.

In this thesis calculations of NPV are compared for different sensitivities scenarios are in terms of oil recovery and in cash flow as well. A full suite of operational and economic parameters will be used. This results in a large number of calculations being needed. No effort will be made to reduce the number of sensitivities - instead the large amount of data generated will be handled by purpose designed software, and distributions of results are plotted.

2.1 Basic Economic Concepts

Economic analyses are an essential aspect of a reservoir management study. The economic performance of a prospective project is often the deciding factor in determining whether or not a project is undertaken. Consequently, it is important to be aware of basic economic concepts and factors that may affect the economic performance of the project.

Economic sensitivity analysis should be performed on key input variables such as oil price, the price of polymer injection, capital expenditure (CAPEX), operating expenditure (OPEX), and oil recovery. The aim is to develop sensitivity analysis graphs for different variables to assess future plans in terms of EOR projects and economics.

The amount of oil to be recovered through EOR application is based on actual reservoir parameters such as; oil saturation, pore volume, permeability, PVT, etc. This estimate is displayed as total incremental EOR production and incremental production per year from the time the project was initiated. The oil recoveries are calculated by using a reservoir simulation model. Cash inflows are generated by the production of oil. Cash outflows are comprised the following investment and operating costs: field development expenditures, equipment expenditures, operating and maintenance costs, injection material costs and other costs.

The cash flow of a project is the net cash generated or expended on the project as a function of time. The time value of money is included in economic analyses by applying a discount rate to adjust the value of money to the value during a base year. The discount rate is the adjustment factor, and the resulting cash flow is called the discounted cash flow. The net present value (NPV) of the cash flow is the value of the cash flow at specified discount rate. It may be represented by the following equation Seba (2003):-

$$NPV = \frac{A_0}{(1+i)^0} + \frac{A_1}{(1+i)^1} + \frac{A_2}{(1+i)^2} + \dots + \frac{A_n}{(1+i)^n} \dots\dots\dots (2.1)$$

$$PV = CF * (1+i)^{-n} \dots\dots\dots (2.2)$$

Where:

PV = net present value

CF = cash flow

i = discount rate

$n = 0$, time origin, origin of discounting

(Figure 2.1) shows a typical plot of NPV as a function of time Fanchi (2006). The discount rate that, applied to all cash flows, returns a zero NPV is called the Internal Rate of Return (IRR).

(Table 2.1) shows the calculation of Net Present Value Index (NPVI) which is a ratio between $NPV(i)$ divided by $MCO(i)$.

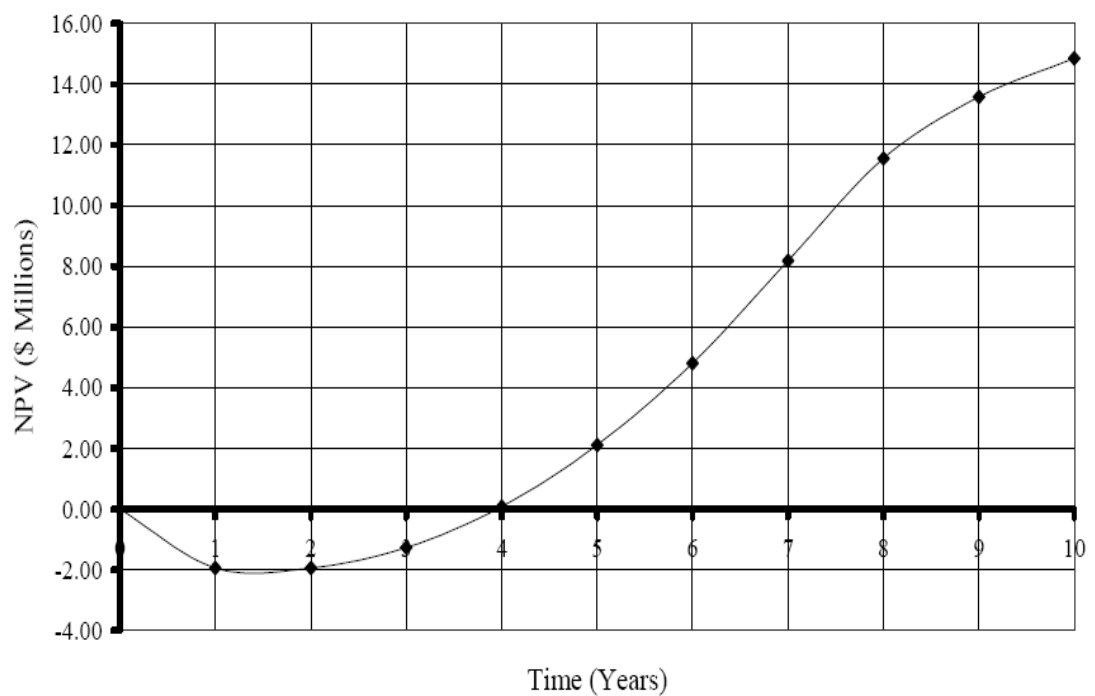


Figure 2.1 typical Cash flow (Fanchi, 2006)

| | |
|--------------------------------|---|
| Capital expenditure (CAPEX) | The amount of money for a company to create or construct anything productive |
| Operating expenditure (OPEX) | The amount of money required for a company to run the productive system. |
| Net Cash Flow (NCF) | The aggregate cash flow for each specific time and represents the impact of the project on the firm over time |
| Discounted rate (DR) | Factor to adjust the value of money to a base year |
| Net present value (NPV) | The sum of all project cash flows, discounted back to a common point in time |
| Payback period | Time when NPV = 0 |
| Maximum Capital Outlay (MCO) | The sum of all capital expenditure- a measure of investment |
| Net present value index (NPVI) | The discounted equivalent of the Profit to investment Ratio (PIR). NPV Index = $NPV(i) / MCO(i)$, Where (i) is the real discount rate. |

Table 2.1 Definition of selected economic measures after Fanchi, 2006

2.2 Discussion

An overview of polymer flooding and economic calculations of associated EOR techniques has been presented here. The literature review focuses on the contributions to knowledge of the other researchers. Most of the literature concentrates on variations in reservoir engineering inputs such as the underlying geological model, fluid properties, wettability, rock properties, aquifer support, micro and macroscopic recovery efficiencies, etc. Often specific data are reported. Thus, these studies achieve a good understanding of the sensitivity to these reservoir engineering parameters and how they will impact hydrocarbon recovery. They also help to identify the types of data that can be used as inputs to the economic modelling. However, in general only one, or at most three (P10, P50 and P90) scenarios are carried forward into the economic models. With a few exceptions fixed economic parameters are generally used. Identification of

these parameters has proved useful for this study, although actual values of some parameters are often not quoted. This may be because these values can represent commercially sensitive data.

What is lacking from the literature is evidence of the output of a full suite of reservoir simulation calculations being used as input to a full suite of economic calculations. This means the decision making processes are based on a limited number of scenarios, and while these may cover the range of possible scenarios, they do not give an indication of the full probability distribution of the outcomes.

In particular most other work in this area has concentrated on using single values for economic variables, whereas the work in this thesis concentrates on the benefit of accounting for a range of reservoir engineering parameters and a range of economic parameters together.

However, this approach of combining a full suite of reservoir simulation calculations and a full suite of economic calculations will result in a very large number of data being generated, and therefore a specific code will have to be developed to handle the output of the large number of Monte Carlo Simulations.

Although all calculations will be restricted to polymer flooding in this thesis, with an understanding of the similarities and the differences between the various non-thermal EOR processes, this tool could also be applied to these other processes, or where a combination of materials is injected.

In chapter 3, the methodology is developed with reference to a simplistic scenario where water flooding, polymer flooding and infill well drilling are compared. The point of chapter 3 is not the outcome, in terms of the decision, but just the mechanics of the process of making that decision.

CHAPTER 3: DEVELOPMENT OF THE METHODOLOGY

Various EOR techniques have been used to recover light oils, heavy oils and tar sands. Thermal processes are mainly used for heavy oils and tar sands, although they can be used for light oils in some situations. Non-thermal techniques are usually implemented in light oil fields and have also been tested for some heavy oils, but with limited success in the field, Thomas (2007).

EOR is a recovery technique in which reservoir sweep is improved by injecting fluids not generally present in the reservoir, Lake (1989). As noted in Chapter 2, these methods increase oil recovery using techniques or resources that are not considered normal pressure support or waterflooding, Martin (1992). During waterflooding operations in the secondary stage, oil is trapped by capillary and viscous forces. Tertiary recovery methods are used to free this oil by injecting chemicals and/or heating the reservoir, Secen (2005). The term EOR is also used to refer to advanced techniques rather than conventional methods.

It is a common observation that operating companies are reluctant to use EOR techniques when they have the option of infill well drilling instead. Reasons for this include the advances in technology that allow accurate prediction of where unswept reserves are located. Other factors include the quicker recovery of the investment, and the fact that oil companies are well experienced in judging the risk and possible returns associated with drilling wells, whereas quantification of the risk and possible returns from EOR projects is difficult to calculate in advance and to evaluate once in place. However, are the oil companies missing opportunities for maximising return on their investment, and are there limitations in the way in which risk is evaluated which inherently favour infill well drilling?

The study involved setting up a range of EOR scenarios, performing reservoir simulation calculations to evaluate additional recovery and then making a comparison with infill drilling to maximise recovery from mature assets. This thesis develops an understanding of how the economic comparison should be performed, since the timescales for investment and return on investment and the associated risks and uncertainties are different for EOR projects and infill well drilling. One driver is

whether the oil price is relatively high or low. The method should involve studying a range of scenarios, selecting appropriate EOR techniques and modelling the impact these techniques have on recovery, and then running calculations of the impact of various options. An economic assessment should be made of the costs and risks of the various options together with expected return under a range of economic scenarios. General classification of these methods is shown in Figure 3.1.

The main challenge for EOR processes at the prevailing oil prices is to reduce the cost. An optimization methodology, combined with an economic model, is implemented for optimizing the net present value of the full field development with an EOR Process. The approach combines an economic package and existing numerical reservoir simulators to optimize the design of a selected EOR process using sensitivity analysis.

After discussion with the operator of a specific field dataset to be used in this study, non-thermal EOR techniques were chosen, and it was decided to compare two specific developments scenarios:

1. Infill well drilling.
2. Conventional polymer flooding.

For each scenario reservoir simulation calculations were performed to define:

1. Oil production rate vs. time.
2. Gas production rate vs. time.
3. Water production rate vs. time.
4. Required water or gas injection rate vs. time.

The production data obtained from the simulation results were imported into an economic model in order to evaluate the project profitability of a particular design. The economic model required the following variables: (1) time, (2) volume of polymer/water injected, (3) cumulative oil recovery, and (4) total fluid production. Discounted-cash-flow analysis was used to economically evaluate each design (Gharbi,

2005). It should be noted that the analysis method has been developed for polymer flooding, but can be adopted for other EOR techniques also.

Our main objective in this thesis chapter is to develop the methodology, and for this purpose the synthetic reservoir simulation model is adequate for the illustration. The technique will involve running a range of reservoir simulation scenarios to test possible recovery outcomes; these outcomes then provide input data that will be used in the probabilistic economic evaluation tool. Figure 3.2 shows the flow charts describing the steps used for the EOR project optimization.

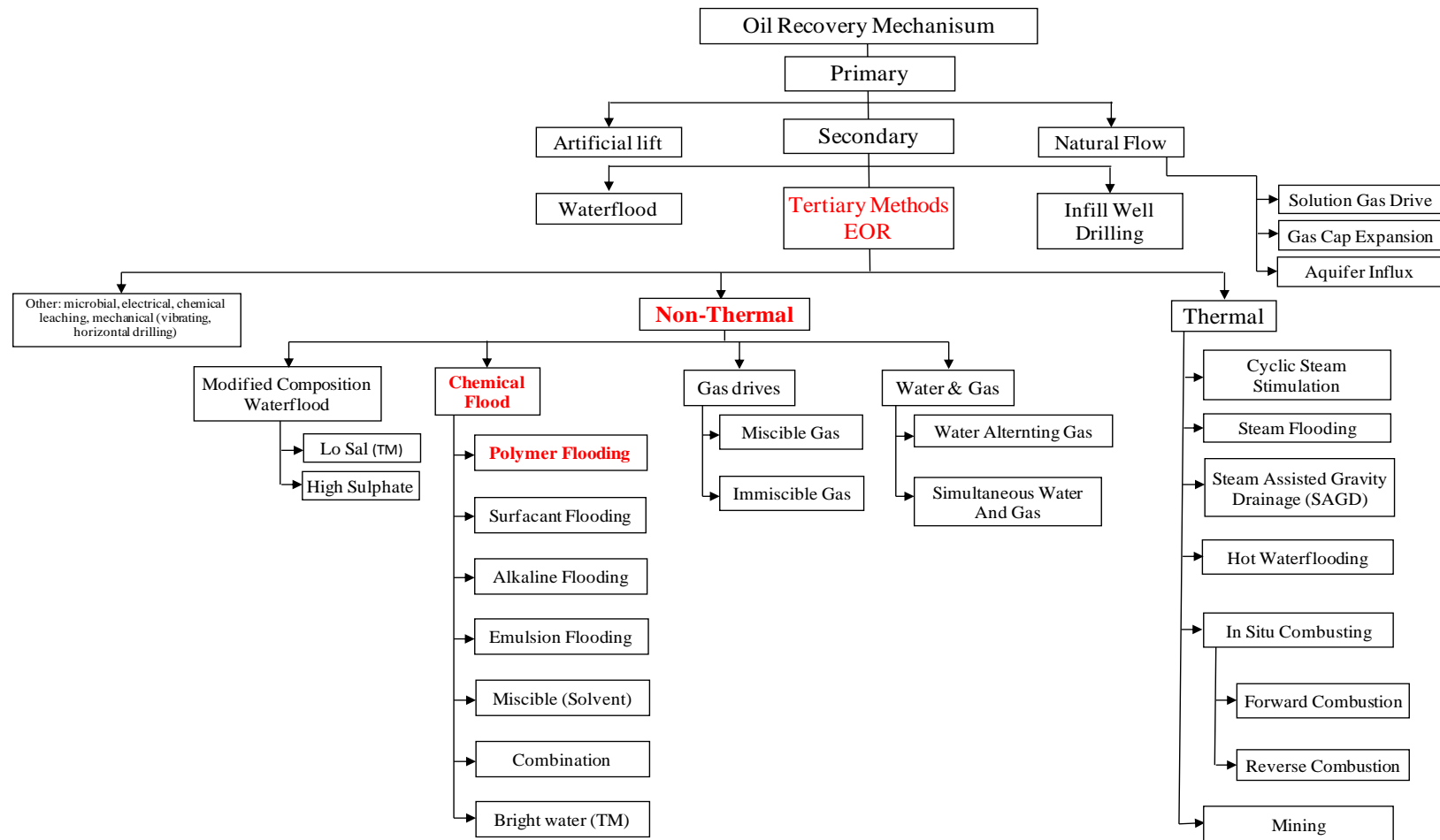


Figure 3.1 EOR Classification

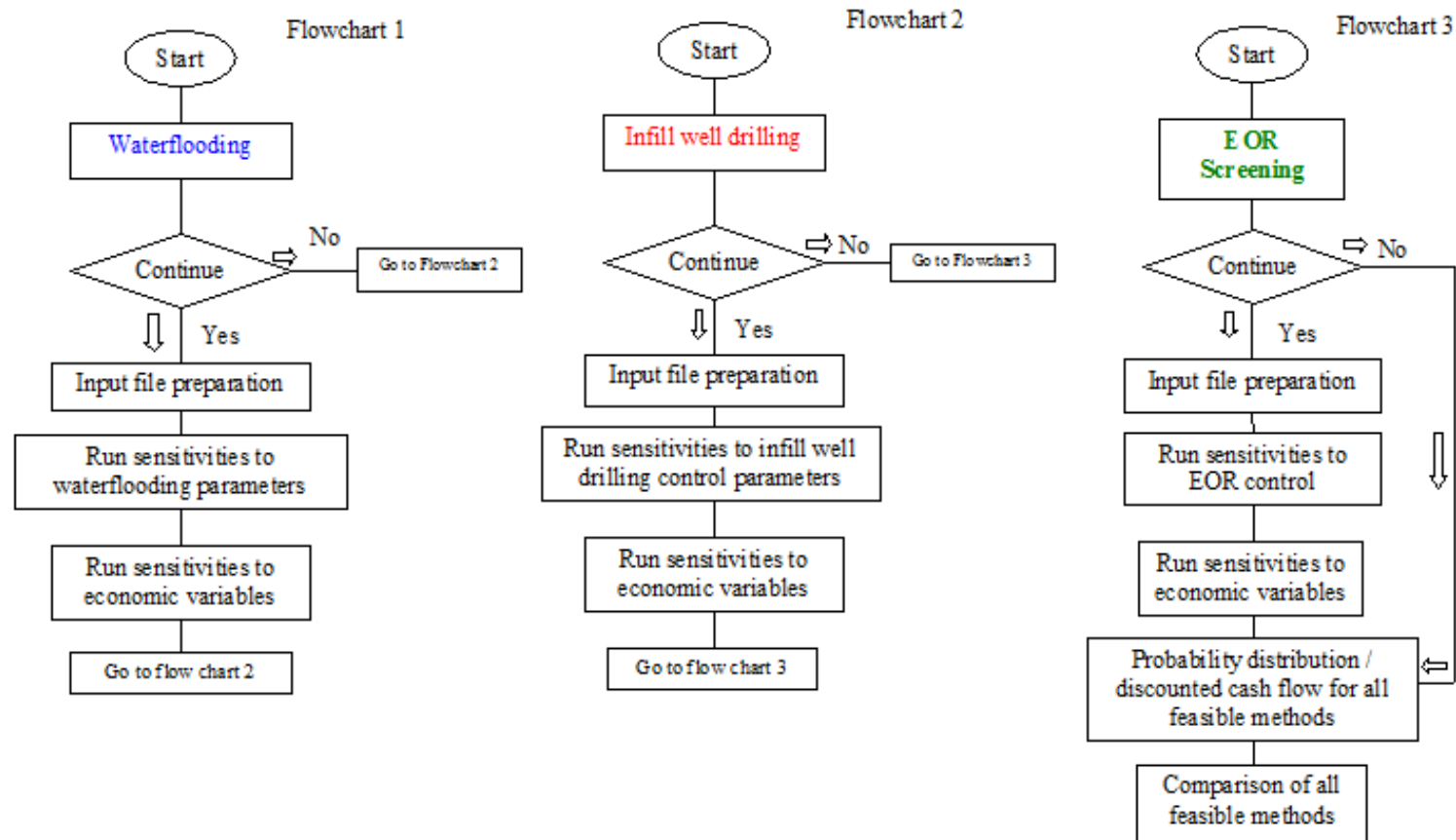


Figure 3.2 Flow chart for the expert system (following Gharbi 2005)

3.1 Development of the reservoir simulation methodology

3.1.1 Reservoir simulation model 1 for polymer flood (Simple two well synthetic model)

Reservoir simulation calculations are performed using Eclipse 100 to compare the EOR process performance to a base-case performance of conventional waterflooding, and to determine the sensitivity of the EOR process to design changes and reservoir uncertainties. The initial activity is to develop a method by using a synthetic reservoir simulation model to study the impact of polymer flooding vs. waterflooding for comparison of the technical feasibility and the economics of EOR. For illustration, a synthetic reservoir simulation model is developed to study the impact of polymer flooding vs. waterflooding. Various uncertainties are tested, and the results are fed into an economic model for an evaluation of sensitivity to the various reservoir engineering parameters and to economic input data.

A Cartesian model Appendix (A1) has been used in this study and run to compare water flooding versus polymer flooding. The reservoir rock consists of three layers with a high permeability layer in the middle. The reservoir simulation models describe the following system:

- 2 wells (1 Injection and 1 Producer)
- The simulation model (Figure 3.10) with dimensions of $X = 2250$ ft, $Y = 1575$ ft and $Z = 150$ ft is divided into three layers with permeabilities of 100 mD, 1000 mD, and 100 mD respectively, with $K_v/K_h = 0.1$, and with porosities of 0.2, 0.22, and 0.2. The initial reservoir pressure was 4000 psi and the production bottom hole pressure (BHP) was 3500 psi.
- The oil viscosity is 1.74 cP and the water viscosity is 0.8 cP. It is assumed that the injected water and the formation water are similar in composition.

It is useful to perform fractional flow analysis of any reservoir system to identify whether it is suitable for any particular recovery process, before a decision is made to undertake detailed reservoir simulation studies.

The fractional flow of water relative to total liquid flow (f_w), ignoring gravity and capillary pressure, is giving by,

$$f_w = \frac{Q_w}{Q_o + Q_w}$$

Where Q_w is the flow rate for water and Q_o is the flow rate for oil.

From Darcy's Law, the water flow rate is given by

$$Q_w = \frac{KA}{L} \frac{K_{rw}}{\mu_w} \Delta P$$

where K is the absolute permeability, A is the cross sectional area, L is the distance over which the pressure difference ΔP is measured, K_{rw} is the relative permeability to water and μ_w is the viscosity of water.

Similarly, for oil

$$Q_o = \frac{KA}{L} \frac{K_{ro}}{\mu_o} \Delta P$$

Substituting we get

$$f_w = \frac{\frac{KA}{L} \frac{K_{rw}}{\mu_w} \Delta P}{\frac{KA}{L} \frac{K_{ro}}{\mu_o} \Delta P + \frac{KA}{L} \frac{K_{rw}}{\mu_w} \Delta P}$$

Then KA/L and ΔP cancel out top and bottom, giving

$$f_w = \frac{\frac{K_{rw}}{\mu_w}}{\frac{K_{ro}}{\mu_o} + \frac{K_{rw}}{\mu_w}}$$

$$f_w = \frac{1}{\left(\frac{K_{ro}}{\mu_o} / \frac{K_{rw}}{\mu_w}\right) + 1}$$

$$f_w = \frac{1}{1 + \frac{K_{ro}}{K_{rw}} \cdot \frac{\mu_w}{\mu_o}}$$

Figure 3.3 and Figure 3.4 show typical plots of normalised relative permeabilities and the corresponding fractional flow curve for this synthetic system.

An important parameter in determining the effectiveness of a waterflood is the end point mobility ratio. The mobility ratio for the synthetic system is greater than 1 which is unfavourable but at approximately 2 is not severe. In addition, the permeability ratio between high and low permeability layers is 10:1. Therefore this is a case that might benefit from polymer flooding although the benefit would only be marginal, and would very much depend on the cost of materials, etc. Although there are reservoirs which are candidates for polymer flooding which have similarly low oil viscosities (<5 cP), for example the Schiehallion Field presented in Chapter 6, the purpose of this set of calculations is to demonstrate the workflow, whatever the outcome may be.

Visual inspection of the waterflood identified areas of unrecovered (bypassed) oil. These resulted from combination of the viscous and the gravitational forces, and the system heterogeneity, and meant that late field recovery was occurring at high water cuts, but with significant recoverable reserves still in place. The main factors were an average permeability ratio between zones of 5 to 1 and inter-well distance of 1125 ft and formation thickness 150 ft.

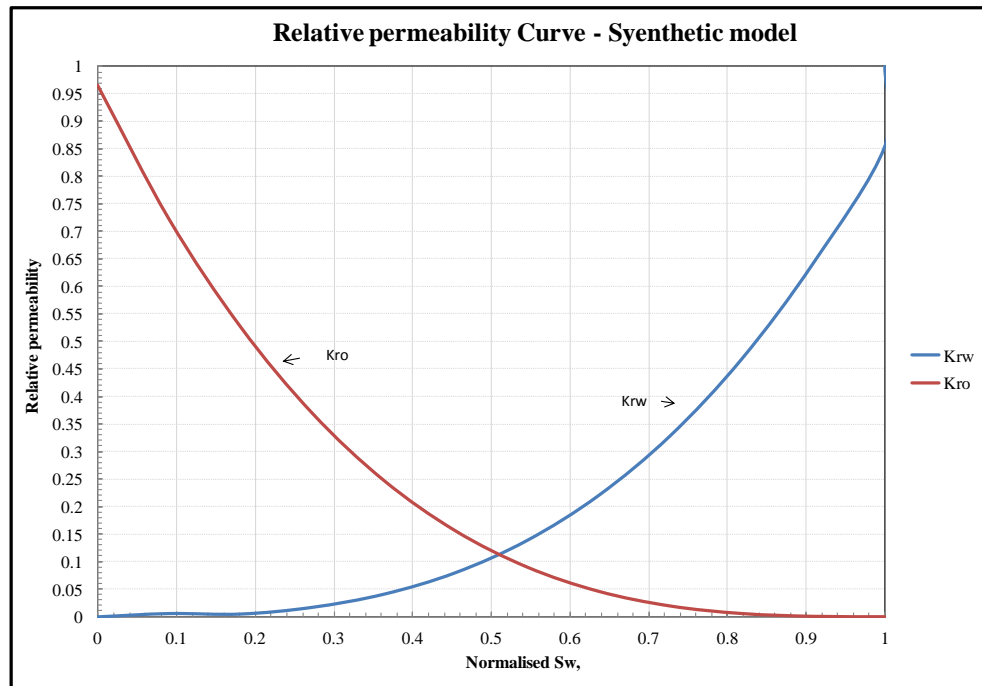


Figure 3.3 - Typical permeability curve for the Synthetic Model

Fractional flow plots for the two cases are shown in Figure 3.4 and the results obtained by applying Welge's graphical technique, at breakthrough, are listed below:

The producing water cut at flood front (f_{wbt}) and the saturation at flood front before water breakthrough (S_{wbt}) are calculated. Then the average saturation at $f_w = 1$, behind flood front after water breakthrough can be evaluated.

Figure 3.4 indicates that for waterflooding, the leading edge of the flood front has a water saturation of 60%. The leading edge of the flood front for polymer flooding has a higher water saturation of 88%.

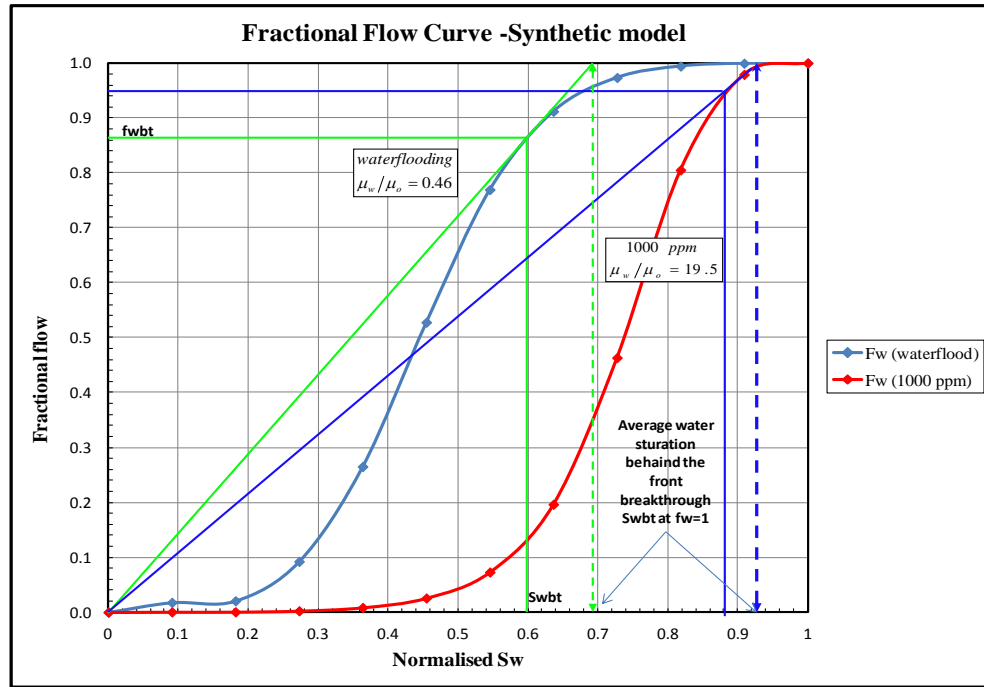


Figure 3.4 - Typical plots of fractional flow curve for the Synthetic Model

The results of the fractional flow can be summarized in Table 3.1 and Table 3.2:

In the waterflooding case the oil-water viscosity ratio is greater than 1 ($\mu_o/\mu_w = 2.2$), leading to a slightly unfavourable mobility ratio ($M=2$), and so oil is bypassed at early breakthrough of water. The oil recovery at breakthrough is 60% of the mobile oil.

In the polymer flooding case ($\mu_o/\mu_w = 0.05$), the mobility ratio is less than one – i.e. is favourable. The oil recovery can be increased to over 88% recovery of mobile oil at breakthrough by addition of polymer at 1000 ppm polymer concentration.

The results obtained by applying Welge's graphical technique, at breakthrough, are listed below in Table 3.1:

| case | S_{wbt} | Reservoir | Surface | $\overline{\overline{S_{wbt}}}$ | $N_{pdpt} (PV)$ |
|----------|-----------|-----------|------------|---------------------------------|-----------------|
| | | f_{wbt} | f_{wsbt} | | |
| WF | 0.60 | 0.86 | 1.02 | 0.69 | 0.60 |
| 1000 ppm | 0.88 | 0.92 | 0.925 | 0.93 | 0.83 |

Table 3.1- Oil recoveries and saturation at breakthrough for Buckley-Leverett method

Values of M and M_s (the mobility ratio at the shock front) for waterflooding and polymer flooding for 1000 ppm polymer concentration are listed below in Table 3.2.

| case | S_{wf} | μ_o/μ_w | $K_{rw}(S_{wf})$ | $K_{ro}(S_{wf})$ | M_s | M |
|------|----------|---------------|------------------|------------------|-------|------|
| WF | 0.60 | 2.2 | 0.18 | 0.06 | 0.47 | 2 |
| 1000 | 0.88 | 0.05 | 0.58 | 0.0007 | 0.03 | 0.05 |

Table 3.2-Values of the shock front and end point relative permeabilities calculated using fractional flow.

To calculate the water saturation profile, firstly the relative permeability ratio K_{ro}/K_{rw} versus water saturation is plotted on a semi log scale to determine the values, and then the fractional flow derivative has to be calculated. For this case, Figure 3.5 shows the fractional flow (f_w) and the fractional flow derivative (dF_w/dS_w) versus the water saturation (S_w) for the waterflooding scenario. Figure 3.6 show the same for polymer flooding at polymer concentration of 1000 ppm.

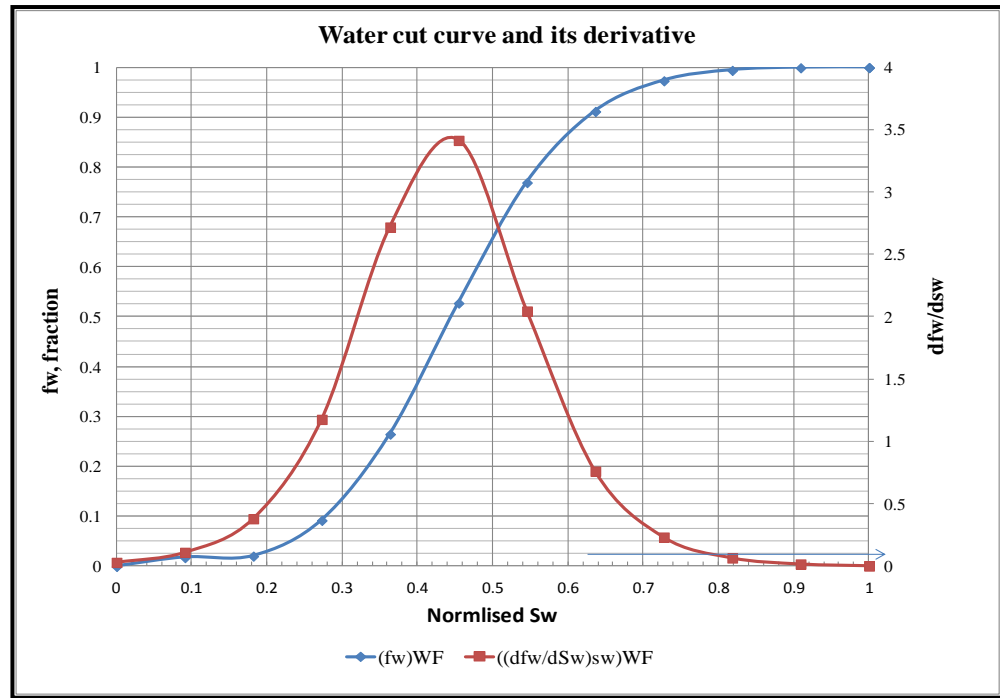


Figure 3.5 - F_w and dF_w/dS_w vs S_w (waterflooding)

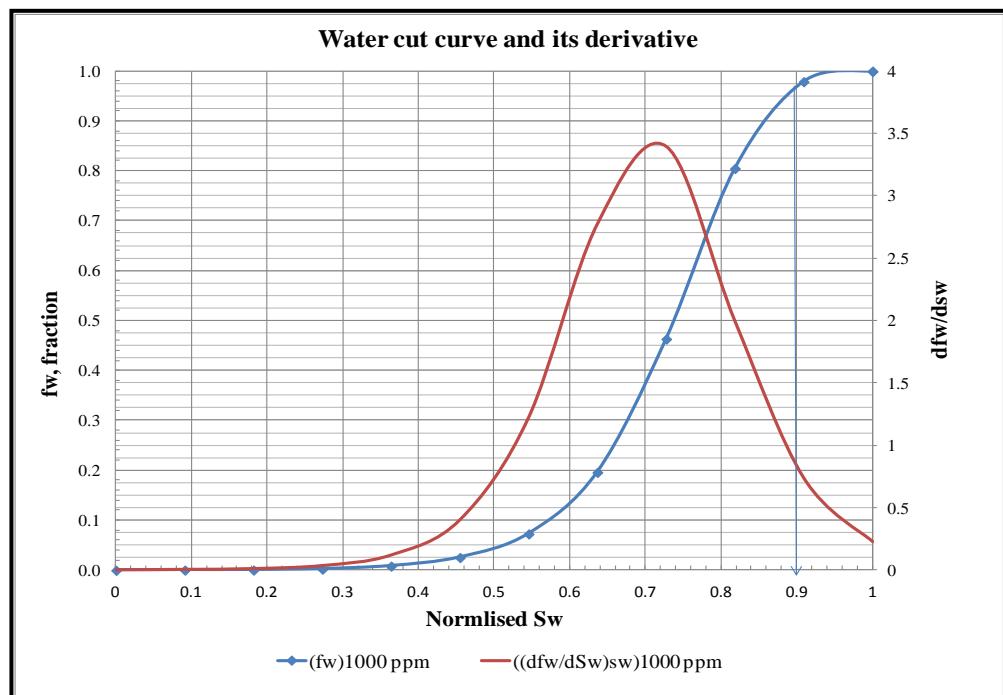


Figure 3.6 - F_w and dF_w/dS_w vs S_w (polymer flood at 1000ppm)

Figure 3.7 shows the shock front at which the water saturation rapidly increases from S_{wc} to S_{wf} . Behind the flood front there is an increase in saturation from S_{wf} to $1-S_{or}$. The time to breakthrough for waterflooding is 0.83PV and the time to breakthrough for polymer flooding is 0.91PV.

This analysis indicates that the mobility ratio is not highly unfavourable, and thus for the waterflood the recovery at water breakthrough is 60% of mobile oil in place. However, the mobility ratio is unfavourable, and thus there is an opportunity to use polymer to increase sweep efficiency and recovery, and use of polymer at a concentration of 1000 ppm could increase the recovery at water breakthrough to 83%. Caution should be used with this type of analysis for a variety of reasons. It is assumed that in the polymer flood case all the water has the viscosity of the polymer solution. However, in front of the polymer slug there will be banking of connate water, and this banked connate water will not be viscosified, and so the recovery when this water breaks through will probably be less than 83%. Also, addition of polymer will entail additional cost. The question that has to be addressed is whether the potential improvement in sweep efficiency and ultimate recovery merits the additional investment. This analysis indicates that there is value in performing the reservoir simulation and economic calculations to address this question.

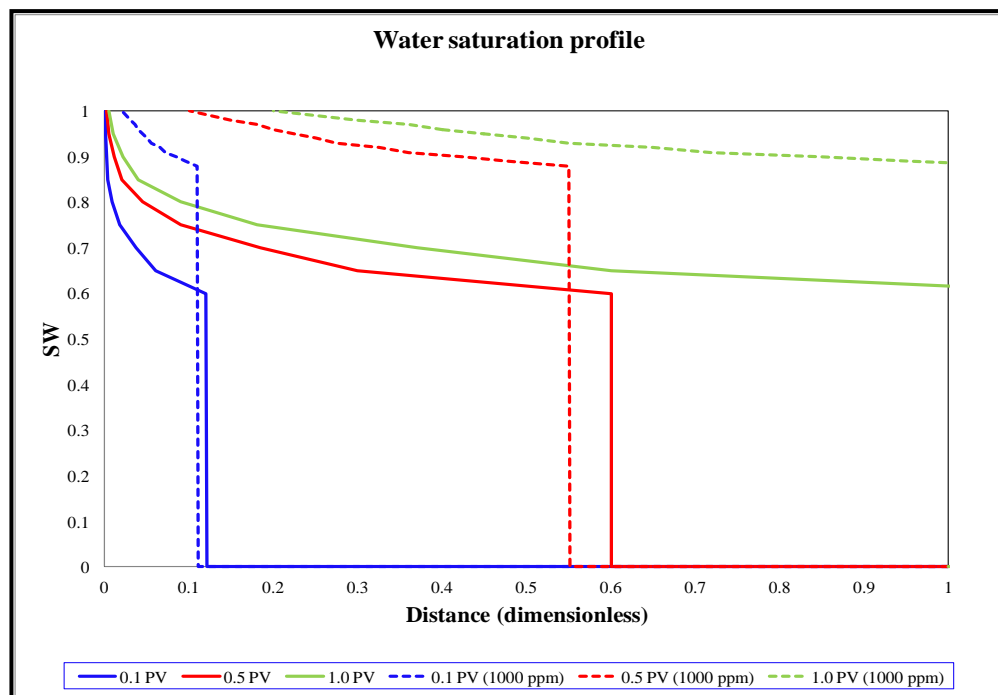


Figure 3.7 - Water saturation profile as a function of distance and time

Polymer is sometimes included in surfactant flooding. The reason for this is that addition of surfactant can reduce the residual oil saturation, mobilising more oil, but it tends to result in a mobility ratio that is more unfavourable than for the conventional waterflood. As an example, Figure 3.8 shows the fractional flow curve for surfactant injection, and compares it to the waterflooding and polymer flooding scenarios already presented. It is clear that water breakthrough occurs at a lower water saturation. In this calculation, the water and oil viscosities have not been changed relative to the base case waterflooding scenario – only the impact of the surfactant on the relative permeability curves has been included. Figure 3.9 shows that the flood front advances more quickly. The subsequent increase in water saturation is more gradual. At the production well, this would translate into early water breakthrough (at 0.65 PVI, compared to 0.83 PVI for the waterflooding case), and a more gradual increase in water cut after breakthrough, compared to the conventional waterflood.

At high flow rates, as occurs near the injection wells, the addition of polymer may have an impact in reducing residual oil saturation somewhat. However, rather than improving only the microscopic sweep efficiency, as surfactant flooding does, polymer flooding primarily acts by increasing the microscopic and the macroscopic sweep efficiency, giving better conformance control and a more piston like displacement. Polymer and surfactant flooding should not be considered as mutually exclusive, and thus addition of polymer to a surfactant flood is used to reduce the impact of early breakthrough that would otherwise occur if only surfactant is used.

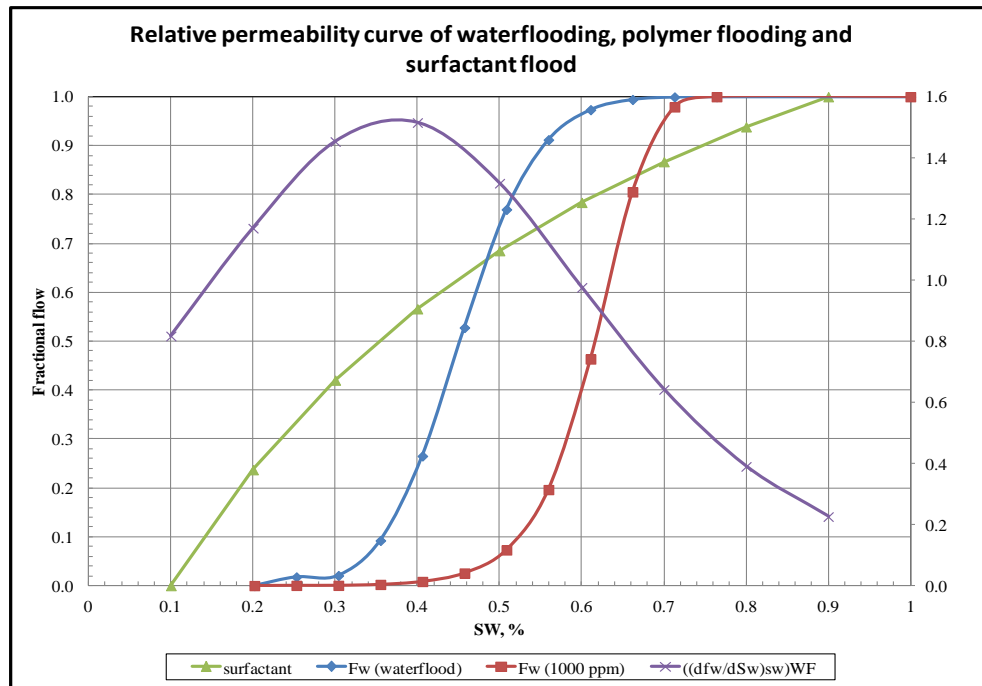


Figure 3.8 - Shows the fractional flow curve for surfactant injection, and compares it to the waterflooding and polymer flooding scenarios

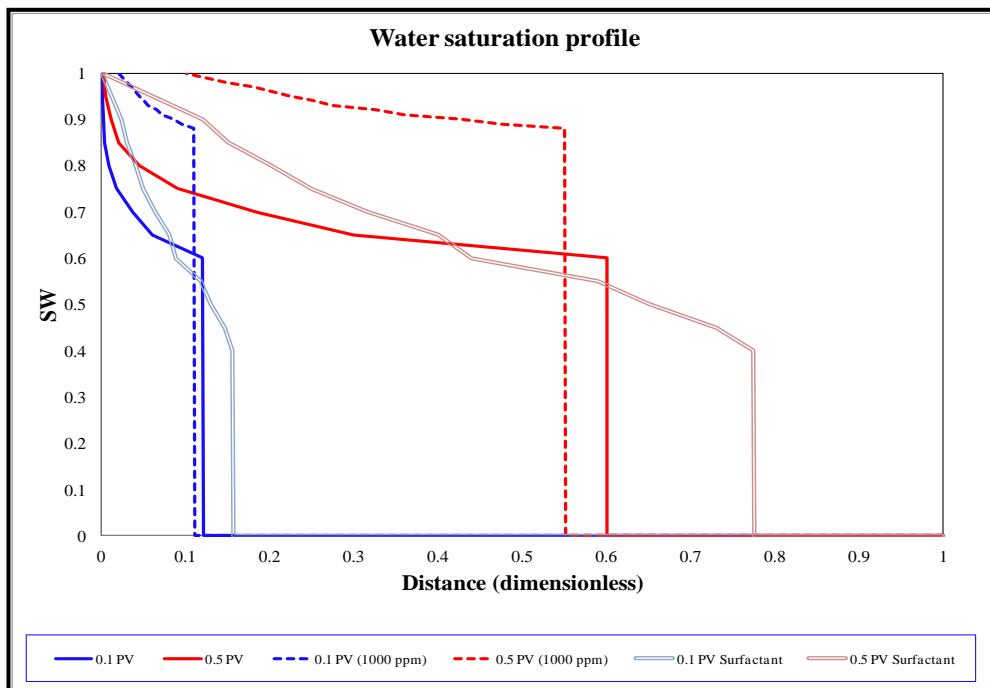


Figure 3.9 - Water saturation profile as a function of distance and time for surfactant injection, and compares it to the waterflooding and polymer flooding scenarios

Having identified that the reservoir simulation study should be conducted, the following input control parameters were included in the model, and sensitivity calculations performed:

- The injecting well was controlled by an injection rate of 2000 bbl/day.
- Concentration of polymer: 100, 200, 500, 1000 and 1500 ppm
- Three contiguous periods of injection:
 - Period of waterflooding (variable)
 - Period of polymer flooding (variable)
 - Period of waterflooding until reach 90% water cut.

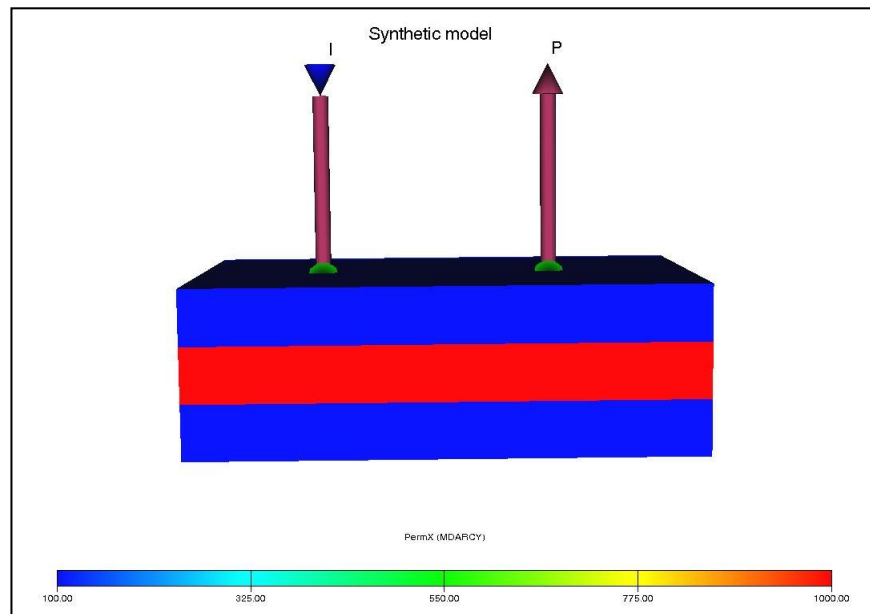


Figure 3.10 Synthetic model, with high permeability layer in the middle.

In the base case, polymer flooding was assumed for 10 years after two years of waterflooding. The technique involved running a range of reservoir simulation scenarios to test possible recovery outcomes using different periods of water flooding and polymer flooding; these outcomes then provide input data that will be used in the probabilistic economic evaluation.

The procedure for the reservoir simulation calculations is as follows:

- 50 sensitivities have been run with polymer concentrations of 100, 200, 500, 1000, 1500 ppm for various durations (see below).
- Three contiguous stages (total time up to 24 years):
 - Stage 1: Water flood
 - Stage 2: Polymer flood
 - Stage 3: Water flood for up to 12 years, depending on WCT
- Stage 1 commences in Year 1, and last for year 2.
- Stage 2 lasts between 1 and 10 years.
- The following output is generated
 - Field oil production total (FOPT)
 - Field water production total (FWPT)
 - Field water injection total (FWIT)
 - Field polymer injection total (WCIT)
 - Field polymer production total (WCPT)

The injection of a polymer solution started in this synthetic model in January 2011, after two years of water flooding. Fifty scenarios have been run at different polymer concentration values over ten years to study the impact of polymer flooding vs. Waterflooding. Table 3.3 show the ten scenarios for the concentration of 1000 ppm and the result is shown in Table 3.5.

| | |
|---------------|----------|
| sensitivity 1 | 100 ppm |
| sensitivity 2 | 200 ppm |
| sensitivity 3 | 500 ppm |
| sensitivity 4 | 1000 ppm |
| sensitivity 5 | 1500 ppm |

| Year 1 | Year 2 | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---------------|--------|-----------------|----------|----------|----------|----------|----------|----------|----------|----------|----------|
| Waterflooding | | Polymerflooding | | | | | | | | | |
| 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
| | | 1000 ppm | | | | | | | | | |
| | | 1000 ppm | 1000 ppm | | | | | | | | |
| | | 1000 ppm | 1000 ppm | 1000 ppm | | | | | | | |
| | | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm | | | | | | |
| | | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm | | | | | |
| | | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm | | | | |
| | | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm | | | |
| | | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm | | |
| | | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm | |
| | | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm |

Table 3.3 Polymer concentration sensitivities

Polymer was added to the injected water at various concentrations of 100, 200, 500, 1000 and 1500 ppm. The injection rate during polymer flooding remained the same as during the conventional water flood. The oil production rate was higher under polymer injection than it was for water flooding until 2020 for all the cases.

The incremental oil is measured as the difference between waterflood and polymer flood oil recoveries and is shown in Figure 3.11. The case with no polymer injection at all gave the poorest recovery, which is 44.9 %, and the various options for timing of polymer injection gave intermediate levels of oil recovery for all cases as shown in Table 3.4.

Table 3.5 shows all the simulation output for the scenario in which 1000 ppm polymer is injected for 10 years. The oil production rates and other data calculated in the various scenarios are then used as input for the economic modelling. However, the key question is not which sensitivity leads to the highest oil recovery, but which one gives the best economic performance. (In the following tables and figures are presented oil recovery data, such as Field Oil Efficiency (FOE), which is defined as the cumulative oil recovery to date divided by the initial oil in place, and is always a fraction between 0 and 1). Polymer adsorption is modelled according to the model in Appendix 1.

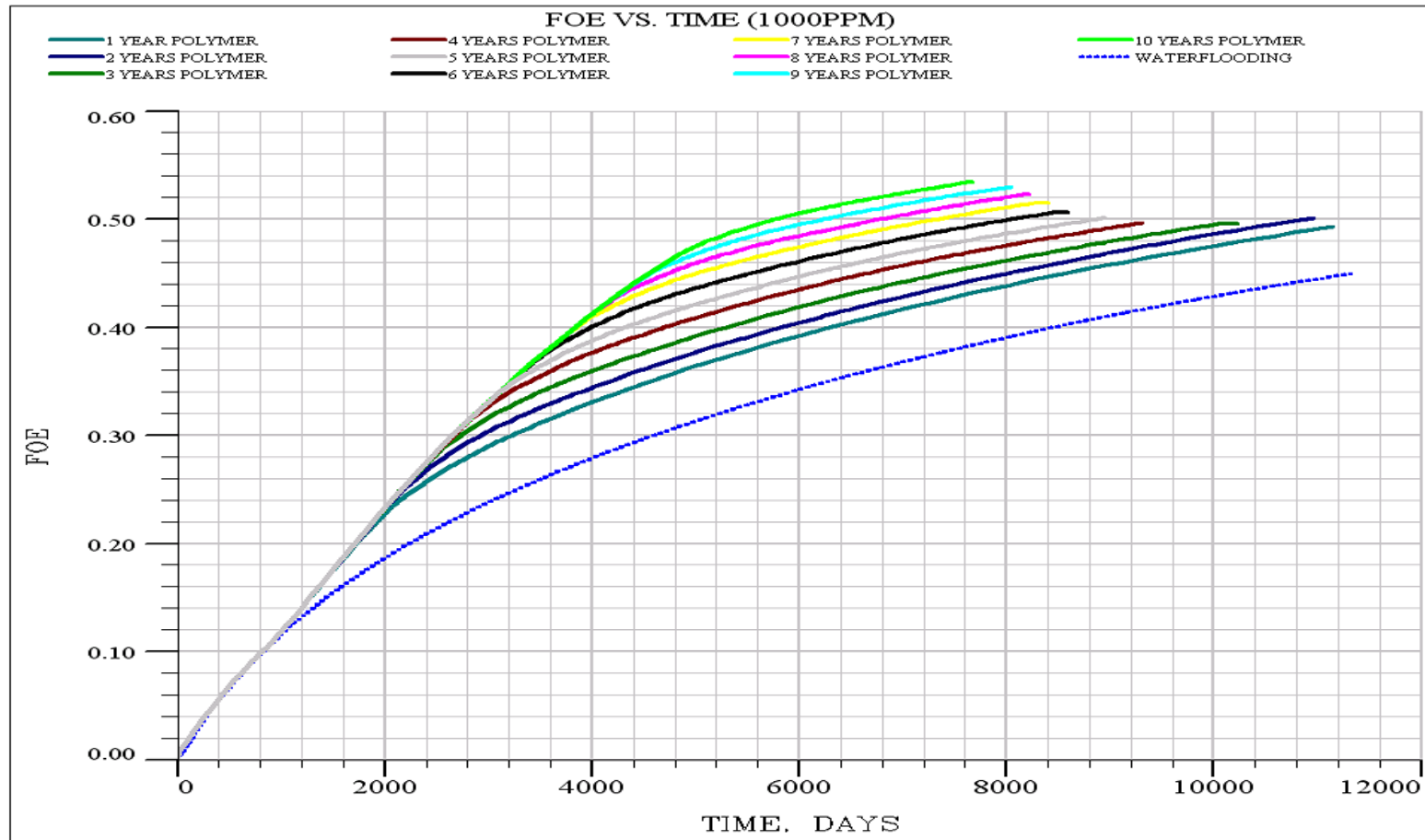


Figure 3.11 Field Oil Efficiency (FOE) for polymer concentration of 1000 ppm

| Polymer Concentration, ppm | FOE, (Fraction) | | | | | | | | | |
|----------------------------|-----------------|--------|--------|--------|--------|--------|--------|--------|--------|---------|
| | 1 Year | 2 Year | 3 Year | 4 Year | 5 Year | 6 Year | 7 Year | 8 Year | 9 Year | 10 Year |
| 100 | 0.46 | 0.47 | 0.47 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.49 |
| 200 | 0.47 | 0.48 | 0.48 | 0.48 | 0.49 | 0.49 | 0.49 | 0.49 | 0.50 | 0.50 |
| 500 | 0.48 | 0.49 | 0.49 | 0.50 | 0.50 | 0.50 | 0.50 | 0.51 | 0.52 | 0.52 |
| 1000 | 0.49 | 0.49 | 0.49 | 0.49 | 0.50 | 0.50 | 0.51 | 0.52 | 0.53 | 0.53 |
| 1500 | 0.49 | 0.49 | 0.49 | 0.49 | 0.50 | 0.50 | 0.51 | 0.52 | 0.52 | 0.53 |

Table 3.4 Recovery factor for all cases

| Years of Polymer flooding | Oil Production, mm bbl | | Incremental Oil Production, mm bbl | Water Production, mm bbl | | Incremental water Production, mm bbl | Water Injection, mm bbl | | Incremental Water Injection, mm bbl | Polymer Injection, mm lbb | Polymer Production, mm lbb |
|---------------------------|------------------------|-------------|------------------------------------|--------------------------|-------------|--------------------------------------|-------------------------|-------------|-------------------------------------|---------------------------|----------------------------|
| | Polymer flood | Water flood | | Polymer flood | Water flood | | Polymer flood | Water flood | | | |
| 1 | 6.0 | 5.4 | 0.6 | 10.6 | 11.4 | -0.8 | 0.73 | 0.73 | 0 | 0.3 | 0.03 |
| 2 | 6.2 | 5.4 | 0.8 | 10.4 | 11.4 | -1.0 | 0.73 | 0.73 | 0 | 0.6 | 0.1 |
| 3 | 6.3 | 5.4 | 0.9 | 10.3 | 11.4 | -1.1 | 0.73 | 0.73 | 0 | 0.9 | 0.1 |
| 4 | 6.5 | 5.4 | 1.1 | 10.1 | 11.4 | -1.3 | 0.73 | 0.73 | 0 | 1.2 | 0.2 |
| 5 | 6.7 | 5.4 | 1.2 | 9.9 | 11.4 | -1.5 | 0.73 | 0.73 | 0 | 1.6 | 0.3 |
| 6 | 6.7 | 5.3 | 1.4 | 9.1 | 10.8 | -1.7 | 0.73 | 0.73 | 0 | 1.9 | 0.4 |
| 7 | 6.9 | 5.3 | 1.5 | 8.6 | 10.8 | -2.1 | 0.73 | 0.73 | 0 | 2.2 | 0.5 |
| 8 | 6.9 | 5.2 | 1.7 | 8.1 | 10.2 | -2.1 | 0.73 | 0.73 | 0 | 2.5 | 0.6 |
| 9 | 7.1 | 5.2 | 1.9 | 7.9 | 10.1 | -2.2 | 0.73 | 0.73 | 0 | 2.8 | 0.8 |
| 10 | 7.1 | 5.1 | 2.0 | 7.0 | 9.5 | -2.5 | 0.73 | 0.73 | 0 | 3.1 | 0.9 |

Table 3.5 Production results for polymer concentration of 1000 ppm

3.1.2 Reservoir simulation model 2 (simple three well synthetic model) for infill well drilling

Infill drilling can be defined as an increase in the number of wells drilled in the field to improve sweep efficiency by reducing the well spacing to contact the unswept oil. In heterogeneous reservoirs, increases in well density can alter sweep patterns, hence increasing the sweep efficiency. Infill drilling can improve oil recovery, but on the other hand it can also lead to more expensive processes than a fluid displacement technique alone would.

A new production well was added to the model in 2011 to compare the recovery factor between infill well drilling and polymer flooding in terms of production. The distance between the oil production well (p) and the new infill well is 450 ft (137 m) Figure 3.12. Total oil production was actually lower for the infill well simulations because in this case it was the water production rate that was accelerated and the water cut exceeded the 90% limit sooner – it was simply not a suitable scenario for infill well drilling due to surface facility constraints.

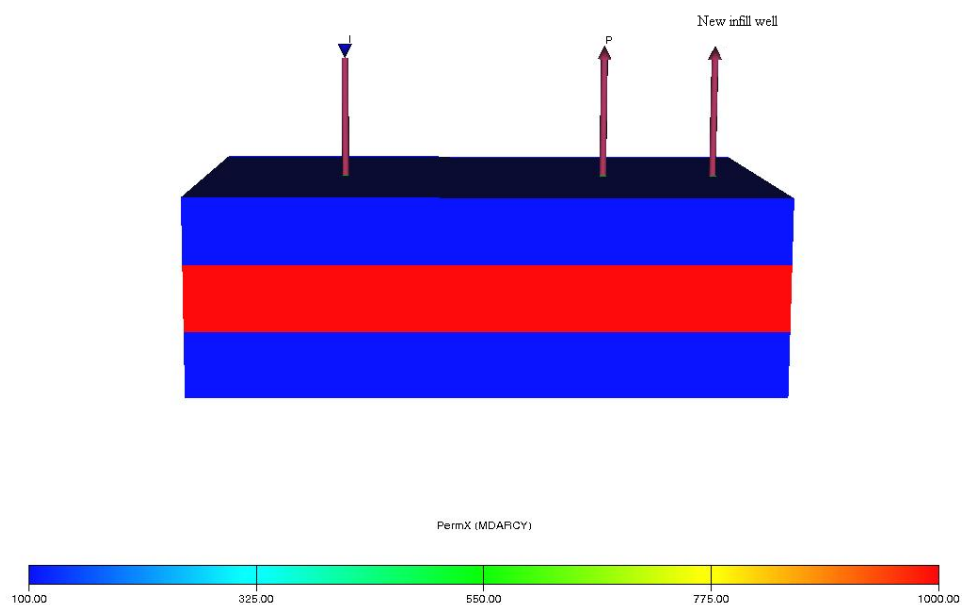


Figure 3.12 Synthetic model, with new infill well

Field Oil Efficiency (FOE) for polymer concentration of 1000 ppm for between 1 and 10 years of polymer flooding, as in Figure 3.11, is now compared to water flooding and the results of the new infill well drilling scenario, as shown in Figure 3.13.

While the water cut limit was reduced earlier in the case with the infill wells, it is evident that it provided accelerated production relative to water flooding, but was on a lower production profile compared to all the polymer flood scenarios using 1000 ppm polymer concentration.

However, as identified above, the interest here is not the recovery profiles, but the impact on overall project economics.

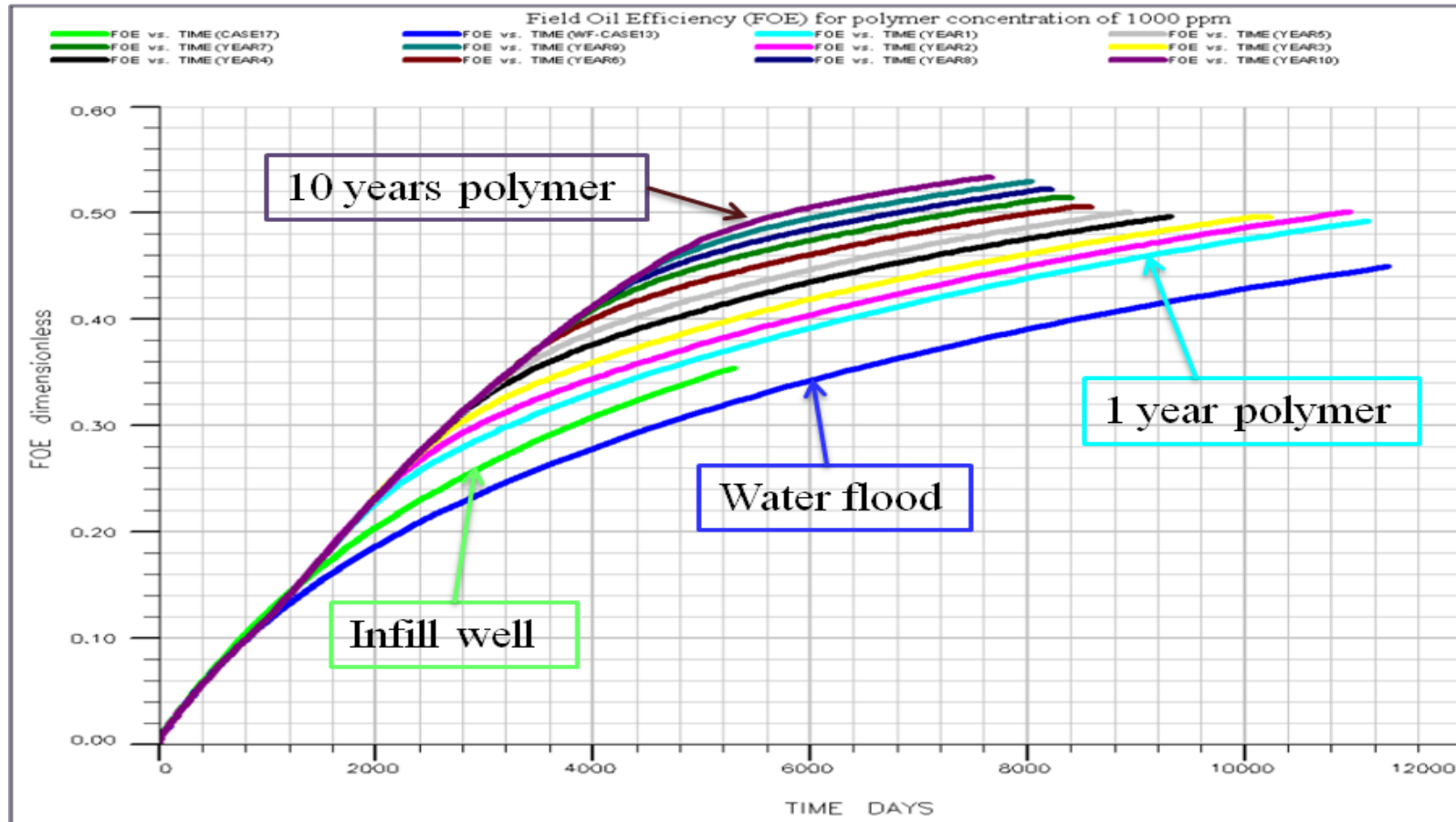


Figure 3.13 Field Oil Efficiency (FOE) for polymer concentration of 1000 ppm for between 1 and 10 years of polymer flooding, compared to water flooding and new infill well drilling

3.2 Development of the economic model methodology

Economic analysis is an essential aspect of a reservoir management study. The economic performance of a prospective project is often the deciding factor in determining whether or not a project is undertaken. Consequently, it is important to be aware of basic economic concepts and factors that may affect the economic performance of the project. Economic sensitivity analysis should be performed on key input variables such as oil price, the cost of polymer injection, capital expenditure (CAPEX), operating expenditure (OPEX), and oil recovery. The aim here is to develop sensitivity analysis graphs for different variables to assess future plans in terms of EOR projects and economics.

Cash inflow is generated by the production of oil. Cash outflow is comprised of the following investment and operating costs: field development expenditures, equipment expenditures, operating and maintenance costs, injection material costs and other costs. The net present value (NPV) of the cash flow is the cash flow at a specified discount rate. All additional oil recovery assists the economics when the cash discounted flows are calculated; however, incremental oil produced earlier is more valuable since it helps to pay back the initial investment more quickly.

The procedure for the economic model is to define the required inputs, perform time based calculations and outputs, as follows:

- Input
 - Results of reservoir simulation calculations (identified above)
 - Economic parameters: infill well drilling cost, incremental well operating expenses, additional capital expenditure, polymer concentration, oil price, incremental oil production cost (IOPC), water injection cost (WIC), water production cost (WPC), polymer cost (PC), incremental polymer production cost (IPPC), incremental polymer injection cost (IPIC)

- Output
 - Incremental cash flow (ICF)
 - Derived performance measures
 - Net present value (NPV)
 - Maximum capital outlay (MCO)

There are significant risks and uncertainties in the oil and gas industry that are associated with production. For the purpose of this study, quantifying uncertainty with ranges of possible values and associated probabilities helps everyone understand the risk involved. In this regard, some of the previous work performed by others who have had studied polymer injection to investigate a wide range of operational and economic parameters that affect polymer flooding was reviewed.

The economic models have been developed for both polymer flooding (the approach could be used for other EOR techniques) and infill well drilling to perform comparative cost calculations, described by a flow chart in Figure 3.2. The economic model of polymer flooding compared to waterflooding is as follows:

1. Incremental oil production (IOP) = Oil production in polymer flood (FOPT) - Oil production in waterflood (FWPT)
2. Incremental water production (IWP) = Water Production in polymer flood (FWPT) - Water production in waterflood (FWPT)
3. Incremental Water Injection (IWI) = Water Injection in polymer flood (FWIT) - Water injection in waterflood (FWIT)
4. Polymer injection (FCIT)
5. Polymer production (FCPT)
6. Revenue from oil production = IOP * Oil Price
7. Incremental Capital Expenditure (ICE)
8. Cumulative incremental capital expenditure (CICE)
9. Polymer purchasing expenditure (PPE) = Polymer Injection * Polymer Cost
10. Incremental oil production expenditure (IOPE) = IOP * IOP Cost

11. Incremental water production expenditure (IWPE) = If Polymer Production ≤ 0 , $(WPPF - WPWF) * WP \text{ cost}$, $(WPPF * (WP \text{ cost} + PP \text{ cost}) - WPWF * WP \text{ cost})$
12. Incremental water injection expenditure (IWIE) = If Polymer Injection ≤ 0 , $(WIPF - WIWF) * WI \text{ cost}$, $(WIPF * (WI \text{ cost} + PI \text{ cost}) - WIWF * WI \text{ cost})$
13. Other incremental operating expenditure (OIOE)
14. Incremental operating expenditure (IOE) = $(PPE + IOPE + OIOE + IWPE + IWIE)$
15. Cumulative incremental operating expenditure (CIOE)
16. Incremental cash flow (ICF) = Revenue from oil production + ICE + IOE
17. Cumulative incremental cash flow (CICF)
18. Incremental cash flow (ICF) @ DR = $ICF * (1 + DR)^{-n}$
19. Cumulative discounted cash flow (CDCF)

The economic model of infill well drilling compared to waterflooding is as follows:

1. Number of new wells drilled and completed this year
2. Number of new wells decommissioned
3. Cumulative number of new wells = Number of new wells drilled and completed this year - Number of new wells decommissioned
4. Incremental oil production (IOP) = Oil production in infill well (FOPT) - Oil production in waterflood (FOPT)
5. Incremental water production (IWP) = Water production in infill well (FWPT) - Water production in waterflood (FWPT)
6. Incremental water injection (IWI) = Water injection in infill well (FWIT) - Water injection in waterflood (FWIT)
7. Revenue from oil production = $IOP * \text{Oil Price}$
8. Incremental well drilling and completion expenditure (IWDCE) = - (Number of new wells * well capital cost)
9. Incremental well operating expenditure (IWOE) = - (Number of new wells * Well operating expense)

10. Incremental well capital expenditure (IWCE) = - (Incremental well drilling and completion expenditure + Incremental well operating expenditure)
11. Cumulative incremental well capital expenditure (CIWCE)
12. Incremental oil production expenditure (IOPE) = - (IOP * IOP Cost)
13. Incremental water production expenditure (IWPE) = - (IWP * IWP Cost)
14. Incremental water injection expenditure (IWPE) = - (IWI * IWI Cost)
15. Other incremental operating expenditure (OIOE)
16. Incremental operating expenditure (IOE) = (IOPE + IWPE + IWIE+ OIOE)
17. Cumulative incremental operating expenditure (CIOE)
18. Incremental Cash Flow (ICF) = Revenue from oil production + IWCE + IOE
19. Cumulative incremental cash flow (CICF)
20. Discounted cash flow (DCF) = $ICF * (1+DR)^{-n}$
21. Cumulative discounted cash flow (CDCF)

3.3 Demonstration use of a synthetic reservoir simulation model and constant economic parameters (compare EOR vs. infill well drilling)

Production data output calculated from simulations of different concentrations of polymer injection and from infill well drilling, were imported into the economic model to evaluate the profitability using the following (base case) economic parameters Table 3.6 were obtained from the literature, Lefebvre et al. (2012), Alsofi et al. (2011); Buchgraber et al. (2009); Wang et al. (2007); Gharbi (2005); Wang et al. (2003);

| | | |
|-------------------------------------|-------|--------|
| Start of Polymer Injection | 2011 | Units |
| Oil Price | 30-50 | \$/bbl |
| Polymer CAPEX | 1 | mm\$ |
| Infill well CAPEX | 5 | mm\$ |
| Discount Rate | 10 | % |
| Incremental Oil Production Cost | 8 | \$/bbl |
| Water Injection Cost | 2 | \$/bbl |
| Water Production Cost | 2 | \$/bbl |
| Polymer Cost | 1.5 | \$/lb |
| Polymer Concentration | 1,000 | ppm |
| Incremental Polymer Injection Cost | 0.5 | \$/bbl |
| Incremental Polymer Production Cost | 0.5 | \$/bbl |

Table 3.6 Parameters in Economic Model

Following are the definitions of the economic parameters specified above:

A. Oil production cost

Cost per barrel is a measure of the cost of creating a system with the capacity to produce one barrel of oil, assuming this can be calculated as total cost divided by total number of barrels produced.

B. Oil price

Crude oil prices measure the spot price of various barrels of oil, most commonly either the West Texas Intermediate or the Brent Blend.

C. Water injection cost

The cost of injecting water into the reservoir to maintain pressure and to displace oil towards the production wells. This includes the cost of injection water treatment facilities, pumps, etc.

D. Water production cost

The cost of surface facilities to treat the oily water produced. The water produced contains a series of organic and inorganic components that may need to be removed before this water can be re-injected in the reservoir or discharged without having a negative environmental impact. These can be classified into three types: primary separation, where hydrocyclones, washing tanks and degasification devices are used; secondary separation, with the use of induced gas flotation and chemical additives; and tertiary separation, which include the use of centrifuges, activated charcoal filters, membrane filters, and additives for bioremediation. The recovery of oil by the water injection technique, which mainly occurs in mature fields, leads to the production of large volumes of water. The produced water (whether from the reservoir or from that injected in operations to boost production) may be in the form of an oil-in-water emulsion (o/w), which needs to be treated to remove the oil before it can be reused or discharged.

E. Polymer cost

The cost of polymer that is injected into the reservoir to improve sweep.

F. Polymer concentration

Polymer concentration determines the polymer viscosity and the size of the required polymer slug.

- Higher injection concentrations cause greater reductions in water cut and can shorten the time required for polymer flooding. For a certain range, they can also lead to an earlier response time in the production wells, a faster decrease in water cut, a greater decrease in water cut, less required pore volumes of polymer, and less required volume of water injected during the overall period of polymer flooding.
- Above a certain value, the injected-polymer concentration has little effect on the efficiency of polymer flooding, and may become detrimental.

G. Polymer injection cost

The cost of the facilities over and above the water injection cost used to inject polymer into the reservoir by increasing the viscosity of the injected water (displacement phase) to approximate it to the viscosity of oil (displaced phase). This is affected by basic wellbore data such as tubing size and depth, casing size and depth and whether the well is completed Open-Hole or, if it is cased, through the target zone and perforated. Other important factors include: current total fluid rate and oil percentage, and pumping fluid levels and static fluid levels, if possible, to help determine the amount of fluid movement required to pump the well off. Any geological information, such as well logs, core analysis reports, geological reports, driller's reports, etc., are extremely helpful. If this information is not available for the subject well, similar information on other wells in the field or area is still a useful tool. An acceptable water source must be identified, which will be used to mix the polymer and chemicals. A packer should normally be run into the well on tubing, and set to isolate the target zone for polymer injection. This eliminates any concerns if other zones are also open, or if there are concerns about casing integrity, since the treatment sometimes requires significant injection pressure during placement. All these factors influence the polymer injection cost.

H. Polymer production cost

The cost of the right equipment and the right application know-how to handle any problem that arises from polymer production including the appropriate disposal of produced polymer.

3.3.1 Polymer modelling results

The production data of the reservoir simulation model for polymer flooding with concentration 1000 ppm from 1 to 10 years only is presented here. Table 3.6 shows the constant parameters in the economic model. The time origin for discounting is 2011, the first year of significant expenditure. Therefore, in 2011, $n = 0$.

Figure 3.14 and Figure 3.16 show discounted cash flow (DCF) by years at discounted rate of 10 %, and \$30 and \$50 oil prices, respectively. Figure 3.15 and Figure 3.17 show typical plots of cumulative discounted cash flow (CDCF) as a function of time at \$30 and \$50 oil prices. The early time of the plot (2009 to 2011) indicates negative NPV; this part of the project is dominated by capital expenses. After 2011 the eventual growth to positive NPV is due to the generation of revenue in excess of expense in **Table 3.7**; the payback period is approximately 1.2 years after the polymer flooding was started.

The calculation of Net Present Value Index (NPVI) from cumulative cash flow data is straight forward, as shown in Table 3.8. A NPVI of 6.30 for the polymer model indicates that there will eventually be a cash surplus of \$6.30 for every dollar invested when a 10 % discount rate and \$30 oil price are used.

A NPVI of 18.50, on the other hand indicates that there will eventually be a cash surplus of \$18.50 for every dollar invested when a 10 % discount rate and \$50 oil price are used. Note that more years of polymer flooding leads to better NPV, because the up-front CAPEX investment is significant.

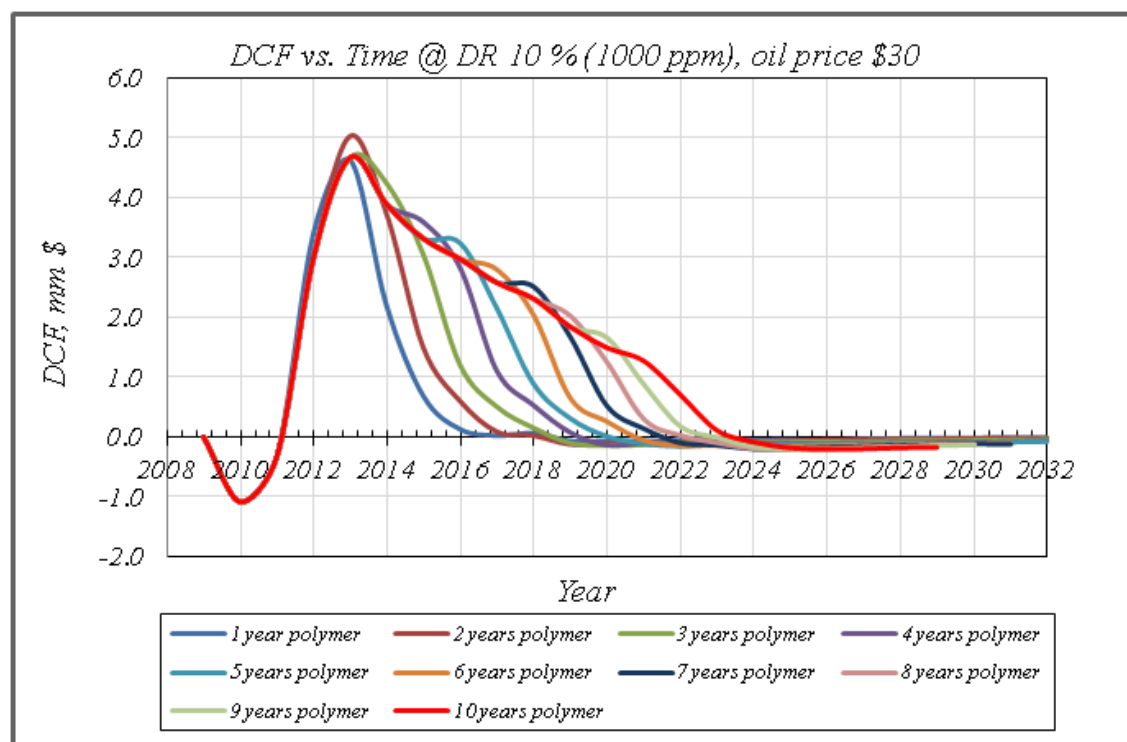


Figure 3.14 DCF for oil price of \$30

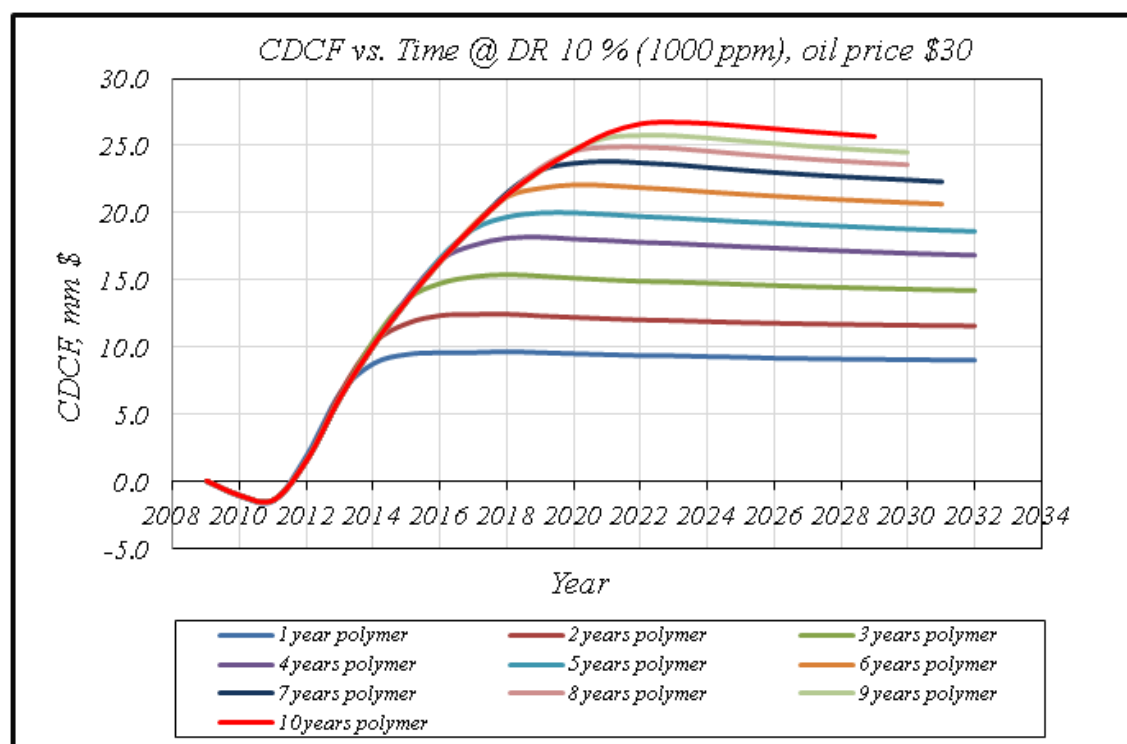


Figure 3.15 CDCF for oil price of \$30

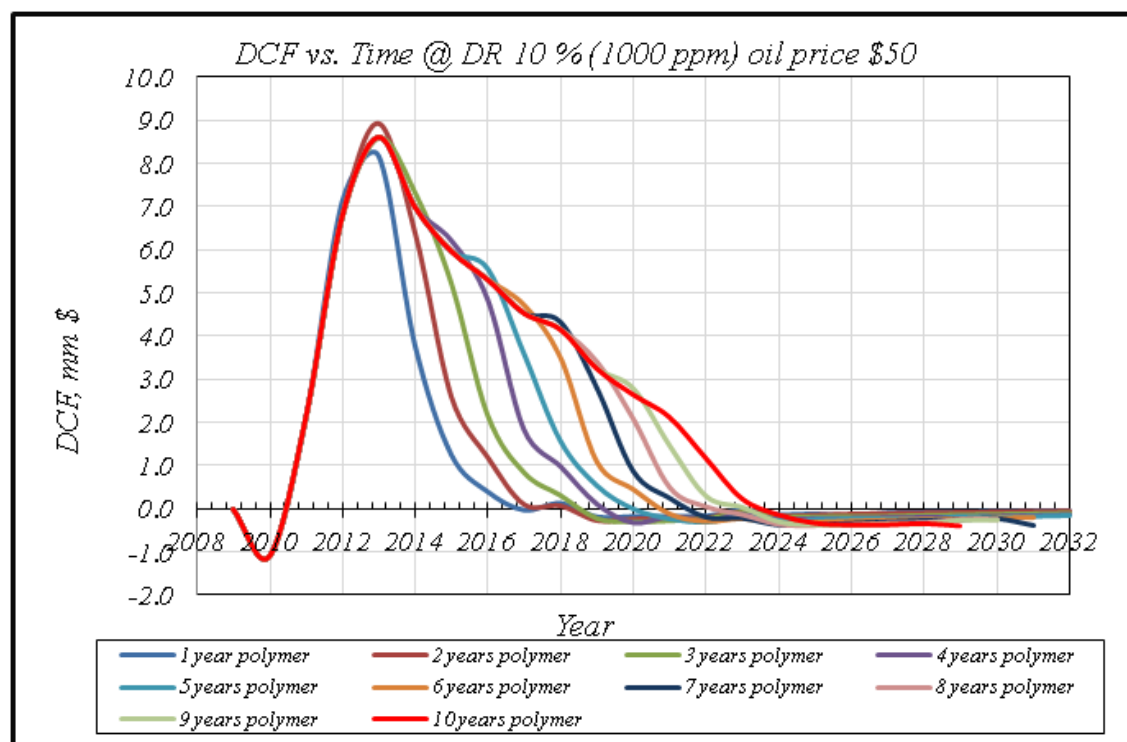


Figure 3.16 DCF for oil price of \$50

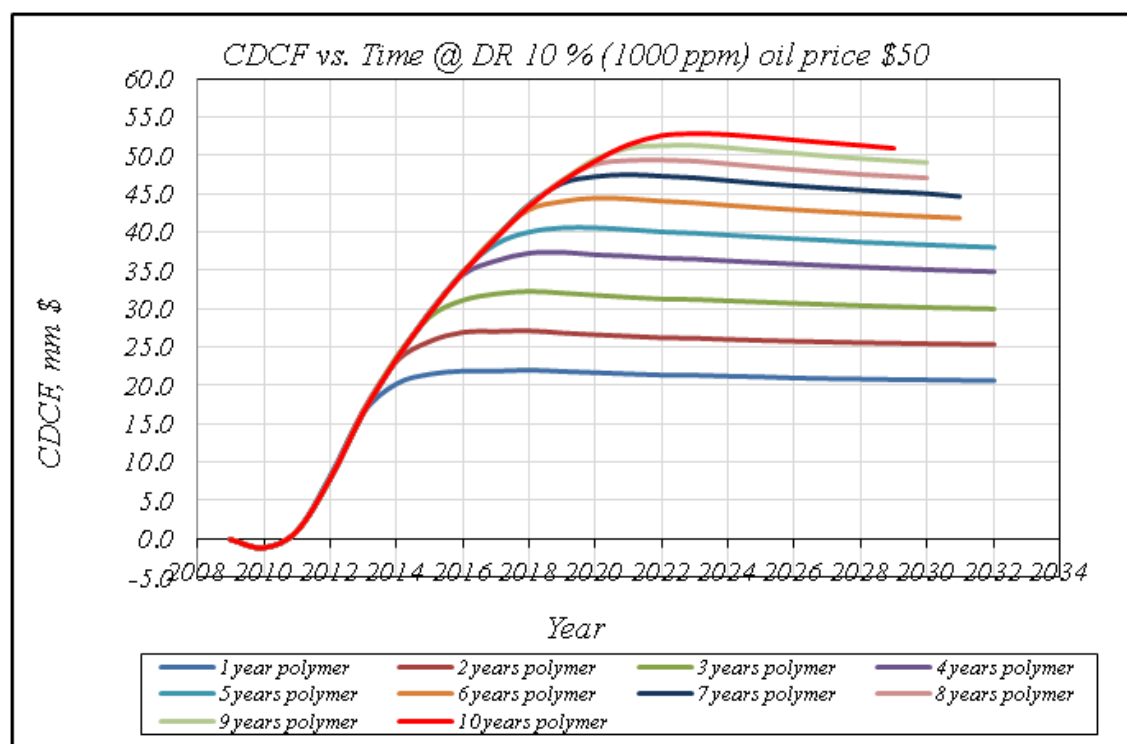


Figure 3.17 CDCF for oil price of \$50

| Years of polymer flooding | NPV @ DR 10 %, oil price \$30, mm\$ | NPV @ DR 10 %, oil price \$50, mm\$ |
|---------------------------|-------------------------------------|-------------------------------------|
| 1 | 9.0 | 20.1 |
| 2 | 11.6 | 25.1 |
| 3 | 14.2 | 30.2 |
| 4 | 16.9 | 35.3 |
| 5 | 18.6 | 38.8 |
| 6 | 20.7 | 42.7 |
| 7 | 22.3 | 45.8 |
| 8 | 23.5 | 48.3 |
| 9 | 24.6 | 50.3 |
| 10 | 25.7 | 52.4 |

Table 3.7 NPV results for oil prices of \$30 and \$50

| Years of polymer flooding | NPVI @ 10 %, oil price \$30 | NPVI @ 10 %, oil price \$50 |
|---------------------------|-----------------------------|-----------------------------|
| 1 | 6.3 | 18.5 |
| 2 | 8.2 | 23.1 |
| 3 | 9.9 | 27.7 |
| 4 | 11.9 | 32.5 |
| 5 | 13.1 | 35.7 |
| 6 | 14.6 | 39.3 |
| 7 | 15.7 | 42.1 |
| 8 | 16.6 | 44.4 |
| 9 | 18.1 | 46.3 |
| 10 | 18.0 | 48.2 |

Table 3.8 NPVI results for oil prices of \$30 and \$50

3.3.2 Example infill well drilling modelling results

Figure 3.18 and Figure 3.20 show discounted cash (DCF) flow by years at a discounted rate of 10 %, and \$30 and \$50 oil prices, respectively. Figure 3.19 and Figure 3.21 show a typical plot of cumulative discounted cash flow (CDCF) as a function of time at \$30 and \$50 oil prices. The early time of the plot indicates positive NPV, because the very quick additional investment is much lower than for polymer flooding.

In 2011 there is negative NPV; this is the part of the project that is dominated by Capital expenses. The payback period is approximately 6 months after the new infill well was started. The eventual growth to positive NPV is due to the generation of revenue in excess of expense, Table 3.9.

The calculation of Net Present Value Index (NPVI) from cumulative cash flow data is straight forward, as shown in Table 3.9. A NPVI of 0.2 for this model indicates that there will eventually be a cash surplus of \$0.2 for every dollar invested when a 10 % discount rate and \$30 oil price are used.

A NPVI of 1.5 for this model indicates that there will eventually be a cash surplus of \$1.5 for every dollar invested when a 10 % discount rate and \$50 oil price are used.

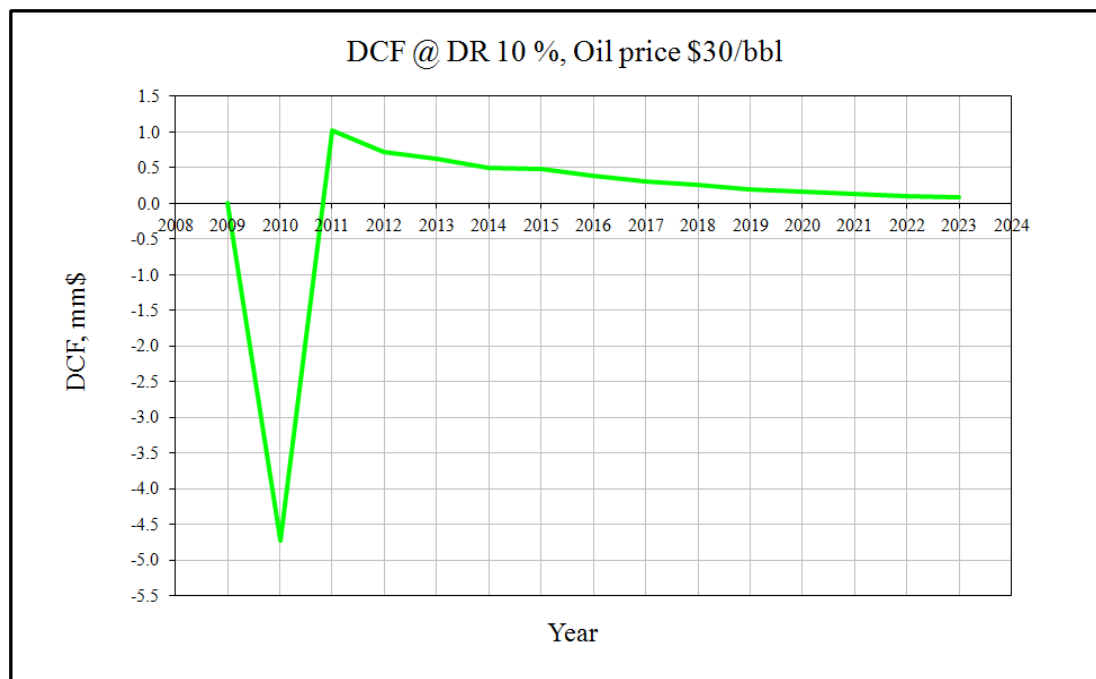


Figure 3.18 DCF for infill well vs. waterflooding

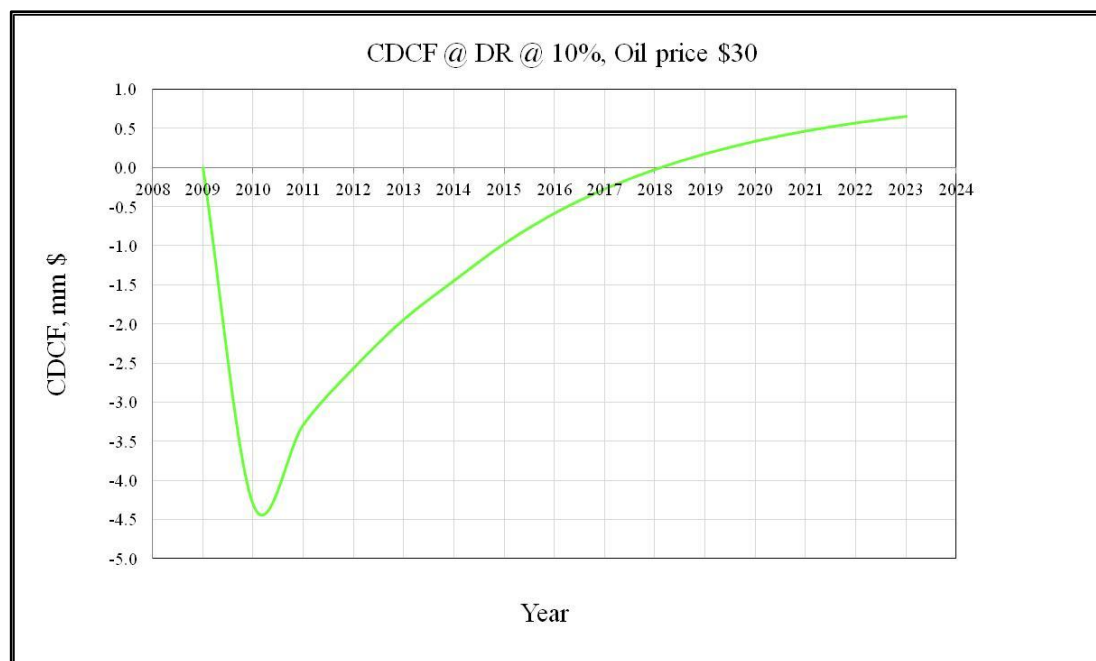


Figure 3.19 CDCF for infill well vs. waterflooding

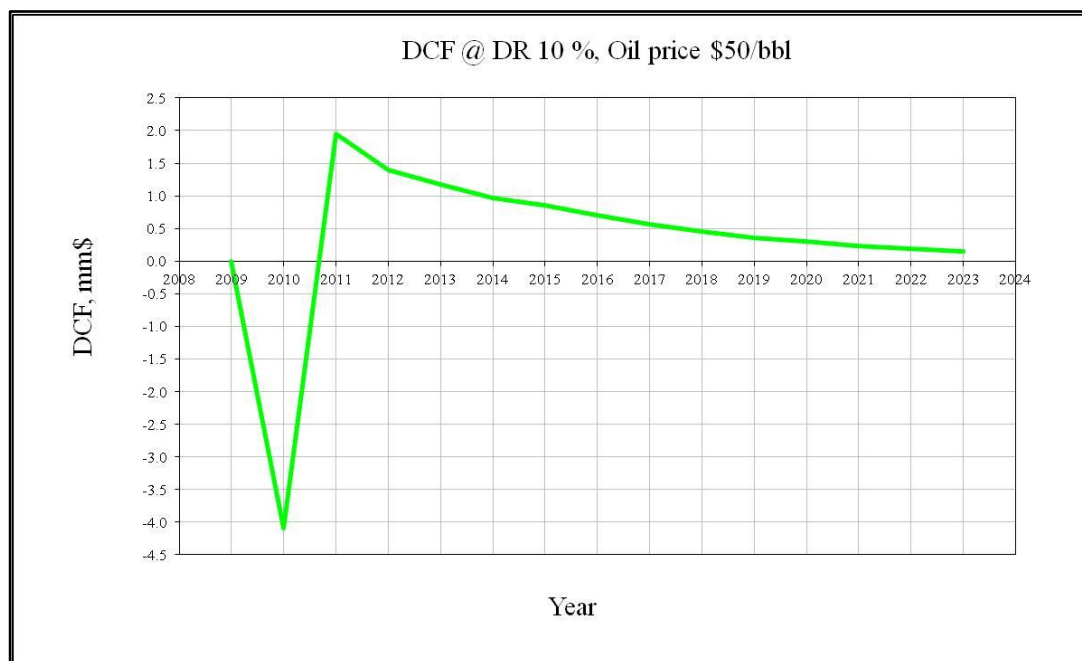


Figure 3.20 DCF for infill well vs. waterflooding

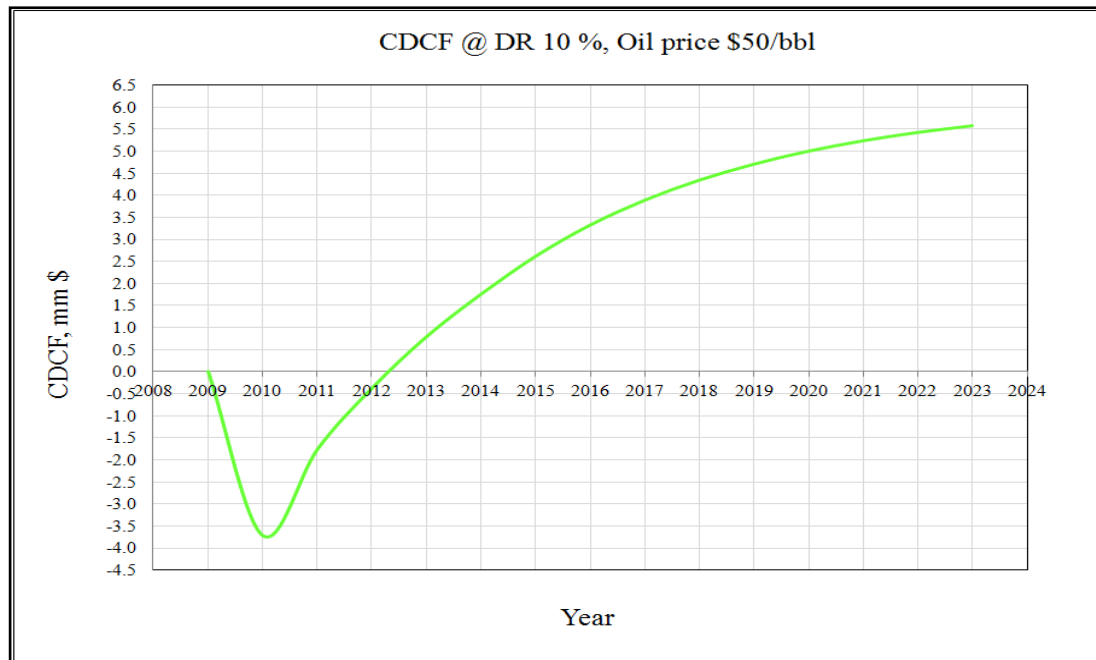


Figure 3.21 CDCF for infill well vs. waterflooding

| | | |
|---------------------------------|------|-------|
| Oil Production in infill well | 3.5 | mmbbl |
| Oil Production in Waterflood | 3.1 | mmbbl |
| Incremental Oil Production | 0.4 | mmbbl |
| | | |
| Water Production in infill well | 5.5 | mmbbl |
| Water Production in Water Flood | 5.9 | mmbbl |
| Incremental Water Production | -0.4 | mmbbl |
| | | |
| Water Injection in infill well | 9.5 | mmbbl |
| Water Injection in Waterflood | 9.5 | mmbbl |
| Incremental Water Injection | 0.0 | mmbbl |
| FOE (Infill Well Drilling) | 35.4 | % |
| | | |
| Revenue from Oil Production | 15.7 | mm\$ |
| Capital Expenses | 5.0 | mm\$ |
| | | |
| NPV @ DR 10 %, oil price \$30 | 1.0 | mm\$ |
| NPV @ DR 10 %, oil price \$50 | 5.4 | |
| | | |
| NPVI @ DR 10 %, oil price \$30 | 0.2 | mm\$ |
| NPVI @ DR 10 %, oil price \$50 | 1.5 | |

Table 3.9 Production & economic model results for infill well vs. waterflooding

3.4 Discussion

In this chapter the basic reservoir simulation calculation that can be performed was demonstrated, and the type of output that can be generated to then provide input for economic calculations was shown. This is identified the type of the economic calculation that can be carried out using such reservoir engineering data and using standard economic variables.

These calculation are performed routinely, and are included in this thesis only as a lead in to the next chapter, where instead of considering a few economic calculations based on a limited set of reservoir engineering scenarios, then consider a method to compare ranges of economic scenarios based on ranges of reservoir simulation sensitivity calculations, to derive a more comprehensive overview of the comparison between different recovery methods, is presented in full, taking full account of the combination of reservoir and economic uncertainties.

CHAPTER 4: IMPLEMENTATION OF COMBINED RESERVOIR SIMULATION AND ECONOMIC MODELS

The objective of this chapter is to conduct an economic analysis to investigate the impact of delaying the start of polymer flooding to identify whether it is better to start polymer flooding earlier or later in the life of the project, and to compare the polymer flooding scenario with a different scenario where infill well drilling is introduced. This is undertaken to illustrate the implementation of combined reservoir simulation and economic modelling. It is achieved by performing a range of sensitivity calculations (reservoir simulation AND economic modeling), using Monte Carlo simulation (MCO) to establish confidence in the method and test uncertainties on key operational parameters input variables. These variables include oil, water and polymer production and injection costs, polymer concentration, timing, etc., and various economic factors such as; oil price, capital expenditure (CAPEX), polymer cost, etc. Sensitivity analysis graphs are developed to assess future engineering planning with regard to the economics of EOR projects.

These sensitivity calculations are numerous, and have been performed by developing a computer program, coded in Java. A total of 1,093,500 economic calculations were performed, based on 225 reservoir simulation calculations. The Java code was developed with the help of a computer programming specialist, who provided the interface Appendix (B). The definition of the calculations included in the program, as well as the running of the calculations and graphing of the results, was undertaken by the author of this thesis alone.

4.1 Extension of reservoir simulation and economic model

4.1.1 Handling variations in reservoir simulation inputs: timing, polymer concentration

The procedure for the reservoir simulation calculations is as follows:

- 225 sensitivities have been run with polymer concentrations: 100, 200, 500, 1000, 1500 ppm.

- Three contiguous stages (total time up to 24 years):
 - Stage 1: Water flood
 - Stage 2: Polymer flood
 - Stage 3: Water flood for up to 12 years, depending on WCT
- Stage 1 commences in Year 1, and lasts between 3 and 11 years.
- Stage 2 lasts between 1 and 9 years.
- The following output is generated
 - Field oil production total (FOPT)
 - Field water production total (FWPT)
 - Field water injection total (FWIT)
 - Field polymer injection total (WCIT)
 - Field polymer production total (WCPT)

Figure 4.1 shows the various permutations of periods of water flooding followed by polymer flooding that maintain a combined total of 12 years or fewer, leading to the 45 sensitivities that were run for each of the five polymer concentrations. Note that although in each case we assume a maximum of 12 years of waterflooding plus polymer flooding, we vary how many years of each in the sensitivity study in annual increments.

A new production well was added to the water flooding model (with no polymer flooding) in 2011 to compare the recovery factor between infill well drilling and polymer flooding in terms of production.

The result of the infill well drilling option in the simple synthetic model showed no significant increase in oil recovery for any timing of drilling the new well. Thus infill well drilling would never be a viable option in this specific scenario, and so no further economic evaluation was carried out for infill well drilling. However, the purpose of these calculations is to demonstrate the methodology, and so in subsequent chapters will present results that include scenarios where infill well drilling *is* economically viable.

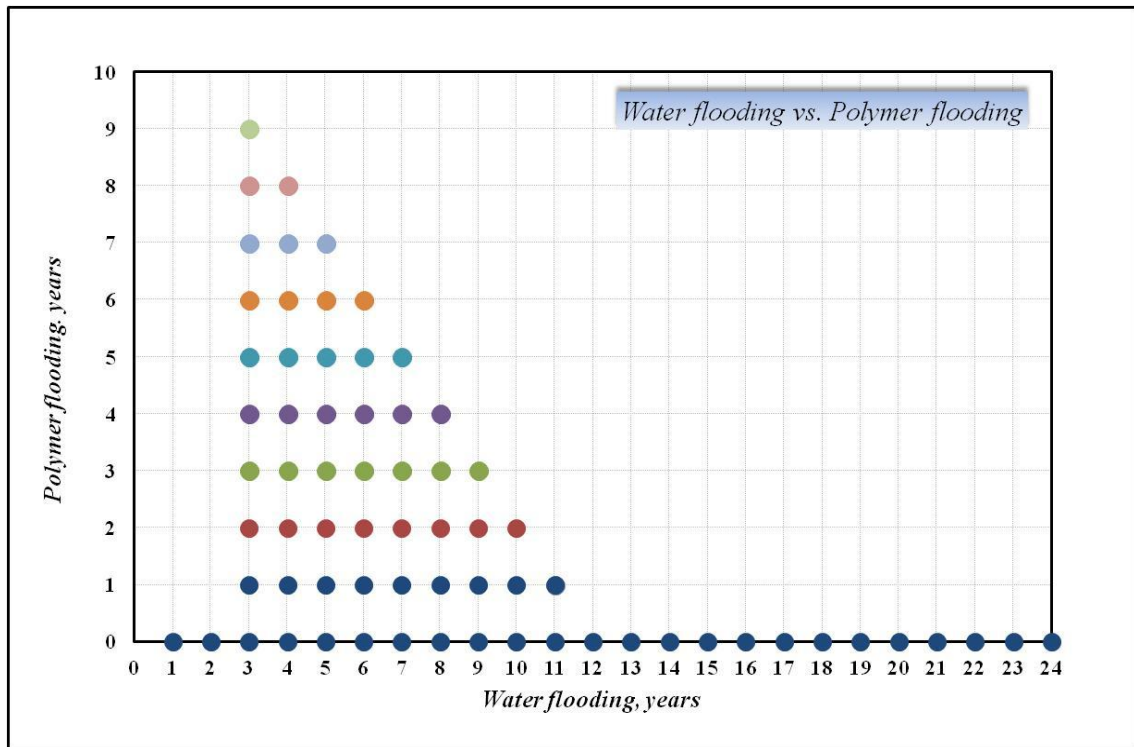


Figure 4.1 Number of years of polymer flooding and ensuing number of years of waterflooding

4.1.2 Handling variations in economic model inputs: polymer cost, oil production, etc.

The procedure for the economic model is as follows:

- Input
 - Results of reservoir simulation calculations (identified above)
 - Economic parameters: infill well drilling cost, incremental well operating expenses, additional capital expenditure, polymer concentration, oil price, incremental oil production cost (IOPC), water injection cost (WIC), water production cost (WPC), polymer cost (PC), incremental polymer production cost (IPPC), incremental polymer injection cost (IPIC)
- Output
 - Incremental cash flow (ICF)
 - Derived performance measures
 - Net present value (NPV)
 - Maximum capital outlay (MCO)

4.1.3 Monte carlo simulation

Monte Carlo Simulation (MCS) is performed to establish confidence in the method, and test economic uncertainties and the risks associated with implementation of polymer flooding. Defining variables with a probability distribution can establish more precisely the economic value of the polymer flooding project. The analysis of uncertainty involves measuring the degree to which input contributes to uncertainty in the output. MCS is a statistics based analysis tool that yields probability impact on Net Present Value (NPV) of the key operational parameters included in the project (oil, water and polymer production and injection costs, polymer concentration, timing, etc.) and various economic factors (oil price, polymer cost, etc).

4.2 Impact of variations in synthetic model

4.2.1 Examples using specific values of economic parameters

Production data output calculated from simulations of different concentrations of polymer injection and from infill well drilling, were imported into an economic model to evaluate the profitability using the following (base case) economic parameters: oil prices in range \$30-\$50/bbl, capital expenditure (CAPEX) is \$1 million, discount rate (DR) is 10%, incremental oil production cost is \$8/bbl, water injection cost is \$2/bbl, water injection cost is \$2/bbl, water production cost is \$2/bbl, polymer cost is \$1.50/lb, polymer injection cost is \$0.50/bbl and polymer production cost is \$0.50/bbl.

Reservoir simulation calculations were performed using ECLIPSE 100 to compare the recovery performance of this EOR method with conventional waterflooding, and to determine the sensitivity of the EOR process to design changes and reservoir uncertainties. The initial activity was to develop a method by using a synthetic reservoir simulation model to study the impact of polymer flooding/infill well drilling vs. waterflooding for comparison of the technical feasibility and the economics of EOR. In each of the simulations, polymer was injected at a constant rate of 2000 bbl/day, with the polymer concentration being varied between the different simulations (100, 200, 500, 1000, and 1500 ppm). For each concentration, 45 scenarios were run, in which the number of years of initial waterflooding, and the number of years of polymer flooding were varied, but ensuring the combined total time of initial waterflooding plus polymer flooding did not exceed 12 years. The results of 45 simulations with polymer

concentration of 1000 ppm are shown in Table 4.1, and the results of the economic sensitivities when the polymer concentration, the oil price is \$50/bbl and discount rate is 10% are illustrated in Figure 4.2 to Figure 4.6 and summarised in Table 4.2. As can be seen in Figures 4.2 to Figures 4.6, NPV increases with increased polymer concentration from 100 ppm to 500 ppm and then there is not much difference above 500 ppm polymer concentration.

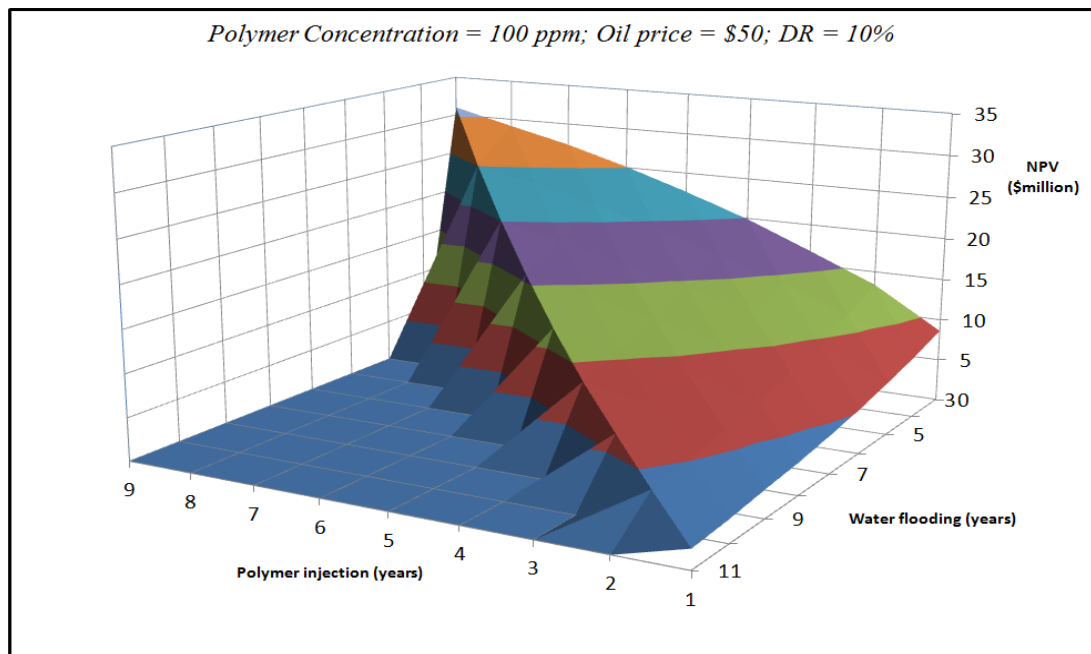


Figure 4.2 NPV vs. years of water flooding and vs years of polymer injection for concentration of 100 ppm.

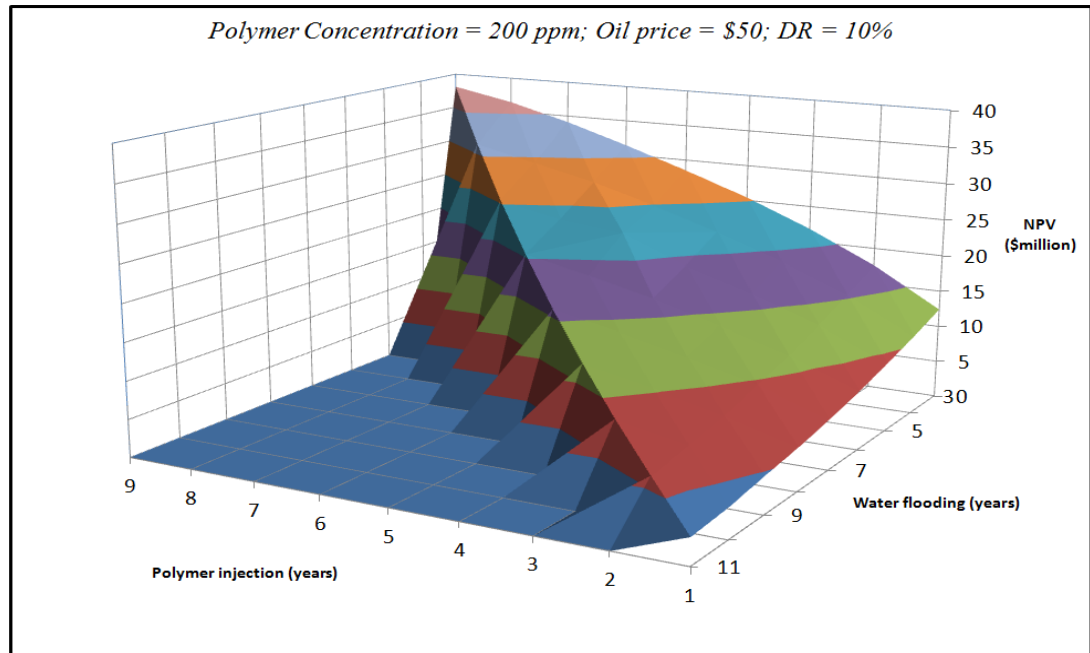


Figure 4.3 NPV vs. years of water flooding and vs years of polymer injection for concentration of 200 ppm.

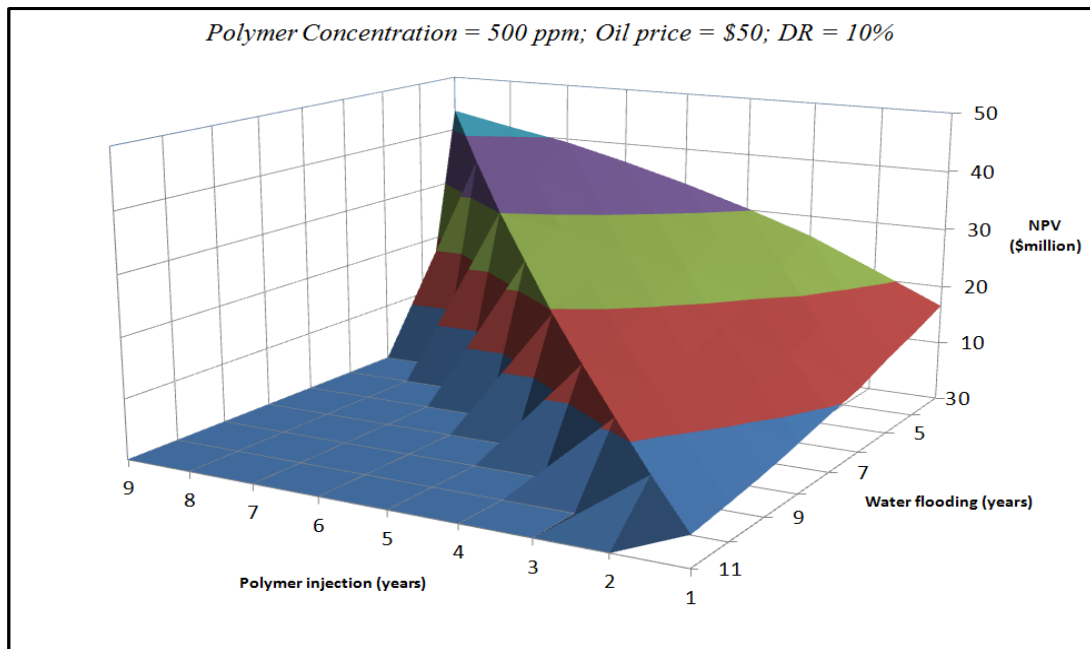


Figure 4.4 NPV vs. years of water flooding and vs years of polymer injection for concentration of 500 ppm.

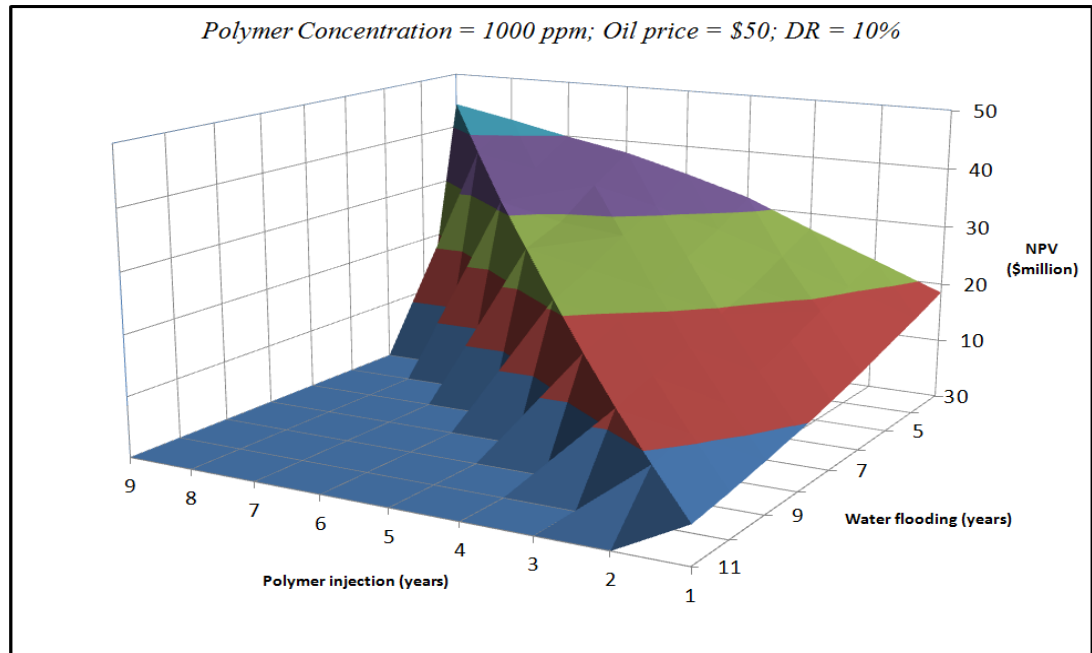


Figure 4.5 NPV vs. years of water flooding and vs years of polymer injection for concentration of 1000 ppm.

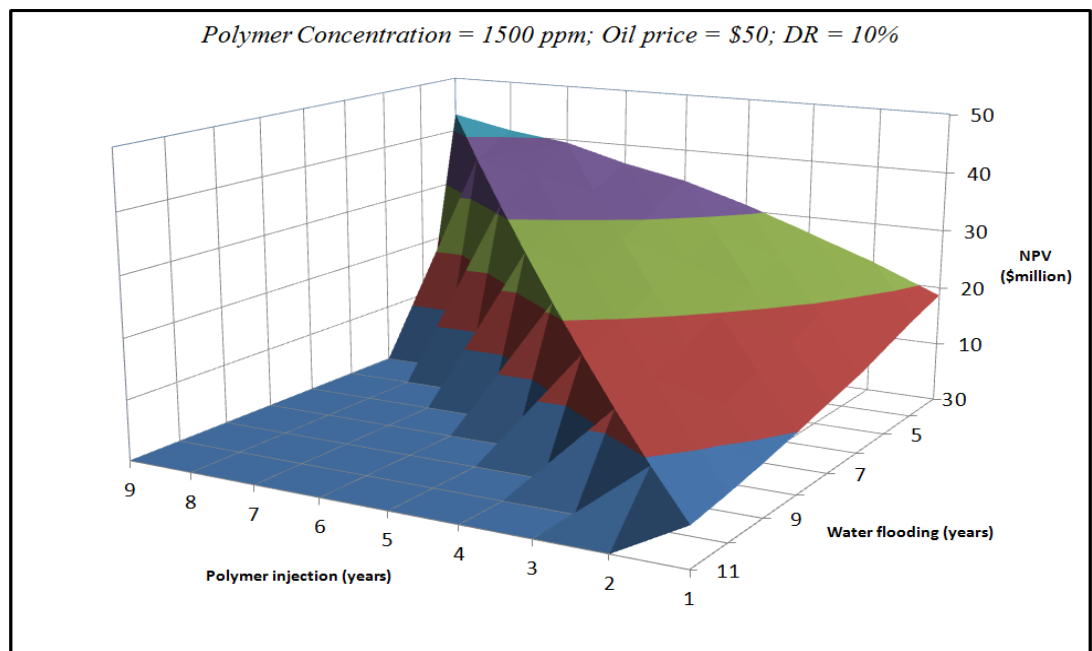


Figure 4.6 NPV vs. years of water flooding and vs. years of polymer injection for concentration of 1500 ppm.

Table 4.1 show the results of reservoir simulation output with polymer concentration of 1000 ppm for various periods of water flooding that combined total of 12 years or fewer, leading to the 45 sensitivities that were run. The more years of polymer injected, the higher the oil recovery. For example, 7.1 mmlb oil is recovered with 3 years of water flooding followed by 9 years of polymer flooding. This is the highest oil recovery compared to the other sensitivities; it would also be beneficial to start injecting polymer as early as possible.

| 1000 ppm | | | | | | | | | | | |
|-------------|------------------------|-------------|------------------------------------|--------------------------|-------------|--------------------------------------|-------------------------|-------------|-------------------------------------|--------------------------|---------------------------|
| Years | Oil Production, mm bbl | | Incremental Oil Production, mm bbl | Water Production, mm bbl | | Incremental water Production, mm bbl | Water Injection, mm bbl | | Incremental Water Injection, mm bbl | Polymer Injection, mm lb | Polymer Production, mm lb |
| | Polymer flood | Water flood | | Polymer flood | Water flood | | Polymer flood | Water flood | | | |
| 3 WF +1PF | 6.1 | 5.4 | 0.7 | 10.6 | 11.4 | -0.8 | 0.73 | 0.73 | 0 | 0.313 | 0.031 |
| 3 WF +2 PF | 6.2 | 5.4 | 0.8 | 10.4 | 11.4 | -1.0 | 0.73 | 0.73 | 0 | 0.625 | 0.079 |
| 3 WF +3 PF | 6.4 | 5.4 | 1.0 | 10.2 | 11.4 | -1.2 | 0.73 | 0.73 | 0 | 0.936 | 0.147 |
| 3 WF +4 PF | 6.6 | 5.4 | 1.2 | 10.0 | 11.4 | -1.4 | 0.73 | 0.73 | 0 | 1.248 | 0.233 |
| 3 WF +5 PF | 6.7 | 5.4 | 1.3 | 9.80 | 11.4 | -1.6 | 0.73 | 0.73 | 0 | 1.561 | 0.330 |
| 3 WF +6 PF | 6.8 | 5.4 | 1.4 | 9.30 | 11.4 | -2.1 | 0.73 | 0.73 | 0 | 1.873 | 0.436 |
| 3 WF +7 PF | 6.9 | 5.4 | 1.5 | 9.00 | 11.4 | -2.4 | 0.73 | 0.73 | 0 | 2.185 | 0.552 |
| 3 WF +8 PF | 7.0 | 5.3 | 1.7 | 8.50 | 10.8 | -2.3 | 0.73 | 0.73 | 0 | 2.496 | 0.676 |
| 3 WF +9 PF | 7.1 | 5.2 | 1.9 | 7.90 | 10.2 | -2.3 | 0.73 | 0.73 | 0 | 2.809 | 0.809 |
| 4 WF +1PF | 6.1 | 5.4 | 0.7 | 10.6 | 11.4 | -0.8 | 0.73 | 0.73 | 0 | 0.312 | 0.030 |
| 4 WF +2 PF | 6.2 | 5.4 | 0.8 | 10.4 | 11.4 | -1.0 | 0.73 | 0.73 | 0 | 0.624 | 0.080 |
| 4 WF +3 PF | 6.4 | 5.4 | 1.0 | 10.2 | 11.4 | -1.2 | 0.73 | 0.73 | 0 | 0.935 | 0.148 |
| 4 WF +4 PF | 6.6 | 5.4 | 1.2 | 10.0 | 11.4 | -1.4 | 0.73 | 0.73 | 0 | 1.248 | 0.235 |
| 4 WF +5 PF | 6.7 | 5.4 | 1.3 | 9.80 | 11.4 | -1.6 | 0.73 | 0.73 | 0 | 1.561 | 0.334 |
| 4 WF +6 PF | 6.9 | 5.4 | 1.5 | 9.60 | 11.4 | -1.8 | 0.73 | 0.73 | 0 | 1.872 | 0.444 |
| 4 WF +7 PF | 7.0 | 5.4 | 2.6 | 9.10 | 11.4 | -2.3 | 0.73 | 0.73 | 0 | 2.184 | 0.562 |
| 4 WF +8 PF | 7.0 | 5.3 | 1.7 | 8.40 | 10.8 | -2.4 | 0.73 | 0.73 | 0 | 2.496 | 0.685 |
| 5 WF +1PF | 6.1 | 5.4 | 0.7 | 10.6 | 11.4 | -0.8 | 0.73 | 0.73 | 0 | 0.312 | 0.030 |
| 5 WF +2 PF | 6.3 | 5.4 | 0.9 | 10.4 | 11.4 | -1.0 | 0.73 | 0.73 | 0 | 0.624 | 0.081 |
| 5 WF +3 PF | 6.4 | 5.4 | 1.0 | 10.2 | 11.4 | -1.2 | 0.73 | 0.73 | 0 | 0.936 | 0.149 |
| 5 WF +4 PF | 6.6 | 5.4 | 1.2 | 10.0 | 11.4 | -1.4 | 0.73 | 0.73 | 0 | 1.248 | 0.238 |
| 5 WF +5 PF | 6.7 | 5.4 | 1.3 | 9.80 | 11.4 | -1.6 | 0.73 | 0.73 | 0 | 1.560 | 0.338 |
| 5 WF +6 PF | 6.9 | 5.4 | 1.5 | 9.70 | 11.4 | -1.7 | 0.73 | 0.73 | 0 | 1.872 | 0.449 |
| 5 WF +7 PF | 7.0 | 5.4 | 1.6 | 9.20 | 11.4 | -2.2 | 0.73 | 0.73 | 0 | 2.184 | 0.562 |
| 6 WF +1PF | 6.1 | 5.4 | 0.7 | 10.6 | 11.4 | -0.8 | 0.73 | 0.73 | 0 | 0.312 | 0.029 |
| 6 WF +2 PF | 6.3 | 5.4 | 0.9 | 10.4 | 11.4 | -1.0 | 0.73 | 0.73 | 0 | 0.625 | 0.080 |
| 6 WF +3 PF | 6.4 | 5.4 | 1.0 | 10.2 | 11.4 | -1.2 | 0.73 | 0.73 | 0 | 0.936 | 0.157 |
| 6 WF +4 PF | 6.6 | 5.4 | 1.2 | 10.0 | 11.4 | -1.4 | 0.73 | 0.73 | 0 | 1.248 | 0.246 |
| 6 WF +5 PF | 6.7 | 5.4 | 1.3 | 9.80 | 11.4 | -1.6 | 0.73 | 0.73 | 0 | 1.560 | 0.351 |
| 6 WF +6 PF | 6.8 | 5.4 | 1.4 | 9.70 | 11.4 | -1.7 | 0.73 | 0.73 | 0 | 1.873 | 0.469 |
| 7 WF +1PF | 6.1 | 5.4 | 0.7 | 10.6 | 11.4 | -0.8 | 0.73 | 0.73 | 0 | 0.313 | 0.029 |
| 7 WF +2 PF | 6.2 | 5.4 | 0.8 | 10.4 | 11.4 | -1.0 | 0.73 | 0.73 | 0 | 0.625 | 0.081 |
| 7 WF +3 PF | 6.4 | 5.4 | 1.0 | 10.2 | 11.4 | -1.2 | 0.73 | 0.73 | 0 | 0.936 | 0.155 |
| 7 WF +4 PF | 6.5 | 5.4 | 1.1 | 10.0 | 11.4 | -1.4 | 0.73 | 0.73 | 0 | 1.248 | 0.244 |
| 7 WF +5 PF | 6.7 | 5.4 | 1.3 | 9.80 | 11.4 | -1.6 | 0.73 | 0.73 | 0 | 1.561 | 0.350 |
| 8 WF +1PF | 6.0 | 5.4 | 0.6 | 10.6 | 11.4 | -0.8 | 0.73 | 0.73 | 0 | 0.312 | 0.028 |
| 8 WF +2 PF | 6.2 | 5.4 | 0.8 | 10.4 | 11.4 | -1.0 | 0.73 | 0.73 | 0 | 0.624 | 0.079 |
| 8 WF +3 PF | 6.4 | 5.4 | 1.0 | 10.2 | 11.4 | -1.2 | 0.73 | 0.73 | 0 | 0.935 | 0.152 |
| 8 WF +4 PF | 6.5 | 5.4 | 1.1 | 10.1 | 11.4 | -1.3 | 0.73 | 0.73 | 0 | 1.248 | 0.241 |
| 9 WF +1PF | 6.0 | 5.4 | 0.6 | 10.7 | 11.4 | -0.7 | 0.73 | 0.73 | 0 | 0.312 | 0.027 |
| 9 WF +2 PF | 6.2 | 5.4 | 0.8 | 10.5 | 11.4 | -0.9 | 0.73 | 0.73 | 0 | 0.624 | 0.077 |
| 9 WF +3 PF | 6.3 | 5.4 | 0.9 | 10.3 | 11.4 | -1.1 | 0.73 | 0.73 | 0 | 0.936 | 0.148 |
| 10 WF +1PF | 6.0 | 5.4 | 0.6 | 10.7 | 11.4 | -0.7 | 0.73 | 0.73 | 0 | 0.312 | 0.026 |
| 10 WF +2 PF | 6.2 | 5.4 | 0.8 | 10.5 | 11.4 | -0.9 | 0.73 | 0.73 | 0 | 0.625 | 0.075 |
| 11 WF +1PF | 6.0 | 5.4 | 0.6 | 10.7 | 11.4 | -1.0 | 0.73 | 0.73 | 0 | 0.313 | 0.025 |

Table 4.1 Reservoir simulation output (polymer concentration of 1000 ppm)

Table 4.2 show the results of specified economic parameters (45 lines of total of 1,093,500 lines of calculated data (here, polymer concentration is 1000 ppm and oil price is \$50/bbl). As can be seen, the higher net present value and the net present value index are at 3 years of water flooding followed by 9 years of polymer flooding.

| 1000 ppm | | |
|-----------------|--|------------------------------------|
| Years | NPV @ DR 10 %, oil price \$50/bbl , mm\$ | NPVI @ DR 10 %, oil price \$50/bbl |
| 3 WF +1PF | 18.5 | 18.49 |
| 3 WF +2 PF | 22.9 | 22.80 |
| 3 WF +3 PF | 27.2 | 27.16 |
| 3 WF +4 PF | 31.8 | 31.79 |
| 3 WF +5 PF | 35.0 | 35.07 |
| 3 WF +6 PF | 37.9 | 37.80 |
| 3 WF +7 PF | 39.9 | 39.88 |
| 3 WF +8 PF | 42.2 | 42.18 |
| 3 WF +9 PF | 44.3 | 44.25 |
| 4 WF +1PF | 16.5 | 18.13 |
| 4 WF +2 PF | 20.6 | 22.62 |
| 4 WF +3 PF | 24.4 | 26.79 |
| 4 WF +4 PF | 28.1 | 30.93 |
| 4 WF +5 PF | 31.2 | 34.29 |
| 4 WF +6 PF | 33.7 | 37.04 |
| 4 WF +7 PF | 35.7 | 39.70 |
| 4 WF +8 PF | 37.7 | 41.46 |
| 5 WF +1PF | 14.7 | 17.81 |
| 5 WF +2 PF | 18.8 | 22.74 |
| 5 WF +3 PF | 21.6 | 26.17 |
| 5 WF +4 PF | 25.3 | 30.61 |
| 5 WF +5 PF | 27.9 | 33.73 |
| 5 WF +6 PF | 29.1 | 36.09 |
| 5 WF +7 PF | 31.6 | 38.21 |
| 6 WF +1PF | 12.8 | 17.09 |
| 6 WF +2 PF | 16.5 | 21.96 |
| 6 WF +3 PF | 19.4 | 25.76 |
| 6 WF +4 PF | 22.1 | 29.44 |
| 6 WF +5 PF | 24.4 | 32.54 |
| 6 WF +6 PF | 26.5 | 35.21 |
| 7 WF +1PF | 11.1 | 16.31 |
| 7 WF +2 PF | 14.2 | 20.74 |
| 7 WF +3 PF | 16.9 | 24.80 |
| 7 WF +4 PF | 19.2 | 28.07 |
| 7 WF +5 PF | 21.5 | 31.46 |
| 8 WF +1PF | 9.6 | 15.39 |
| 8 WF +2 PF | 12.3 | 19.77 |
| 8 WF +3 PF | 14.7 | 23.69 |
| 8 WF +4 PF | 16.8 | 27.01 |
| 9 WF +1PF | 8.3 | 14.72 |
| 9 WF +2 PF | 10.7 | 18.89 |
| 9 WF +3 PF | 12.7 | 22.45 |
| 10 WF +1PF | 7.1 | 12.98 |
| 10 WF +2 PF | 9.2 | 16.67 |
| 11 WF +1PF | 6.1 | 10.98 |

Table 4.2 Example of specified economic parameters (45 lines of total of 1,093,500 lines of calculated data (here, polymer concentration is 1000 ppm and oil price is \$50/bbl)

4.2.2 Sensitivity and risk analysis including all values of economic parameters

There are significant risks and uncertainties in the oil and gas industry that are associated with production. For the purpose of this study, quantifying uncertainty with ranges of possible values and associated probabilities helps everyone understand the risk involved. In this regard, we have been through some of the previous work performed by others who have had studied polymer injection to investigate a wide range of operational and economic parameters that affect polymer flooding.

The variables that are used in this chapter to optimize the design, using project profitability measures as the decision making in the economic model are given in Table 4.3, and were obtained from the literature, Lefebvre et al. (2012), Alsofi et al. (2011); Buchgraber et al. (2009); Wang et al. (2007); Gharbi (2005); Wang et al. (2003). While the literature in some places gives ranges of values, which have been used here, for other parameters single values only are given. The objective of this analysis was to use ranges of parameters. However, certain parameters, such as the cost of specific types of polymer, can represent highly sensitive commercial information. As a result, building on the values given in the literature, ranges were proposed. The operator supporting this project was prepared to review the ranges proposed, and indicate that they were appropriate ranges for conditions such as those that prevail in the offshore North Sea oil industry, but without specifying where in that range the options they were considering lie. This was deemed the most suitable method to address the issue of obtaining information which is not available in the public domain, but which was required as input to this research activity, and without breaking any commercial confidentiality.

| EOR technique | Water flooding | Polymer flooding | Infill well drilling |
|--|-----------------------|--------------------------|-----------------------------|
| Duration of water flooding, year | 3 to 11 | 3 to 11 | 3 to 11 |
| Duration of polymer flooding, year | - | 1 to 9 | 1 to 9 |
| New infill wells | - | - | 1 |
| Infill well drilling cost, mm\$ /well | - | - | 5-10-15-20-25 |
| Incremental Well Operating Expenses, mm\$/yr | - | - | 0.5-1-1.5-2-2.5 |
| Additional capital expenditure, mm\$ | - | 0.23-0.30-0.52-0.88-1.24 | 0 |
| Polymer concentration, ppm | - | 100-200-500-1000-1500 | - |
| Oil Price, \$/bbl | 30-50-80-115-150 | 30-50-80-115-150 | 30-50-80-115-150 |
| Incremental oil production cost, \$/bbl | - | 8-10-12 | 8-10-12 |
| Water injection cost, \$/bbl | 1-2-8 | 1-2-8 | 1-2-8 |
| Water production cost, \$/bbl | 1-2-3 | 1-2-3 | 1-2-3 |
| Polymer cost, \$/lb | - | 1-2-3-4 | - |
| Incremental polymer production cost, \$/bbl | - | 0-0.5-1 | - |
| Incremental polymer injection cost, \$/bbl | - | 0.25-0.5-1 | - |

Table 4.3 Ranges used for economic parameters.

Figure 4.7 shows the relation between net present value and polymer concentration at different oil prices of \$30, \$50, \$80, \$115, and \$150/bbl with economic parameters set as follows: water flooding 3 years; IOPC \$8/bbl; WIC \$1/bbl; WPC \$1/bbl; PC \$1/lb; IPPC \$0/bbl; IPIC \$0.25/bbl.

The observations from the graphs are as follows:

- At low oil price, as concentration increases NPV rises then falls
- At high oil price, as concentration increases NPV rises continually, although the rate of increase is lower at high concentrations
- The later the start in polymer flooding, the lower the NPV
- The more years of polymer flooding, the higher the NPV (the lowest curve on each graph is for 1 year of polymer flooding, the highest curve is for 9 years, with the lines in between increasing by one year at a time)

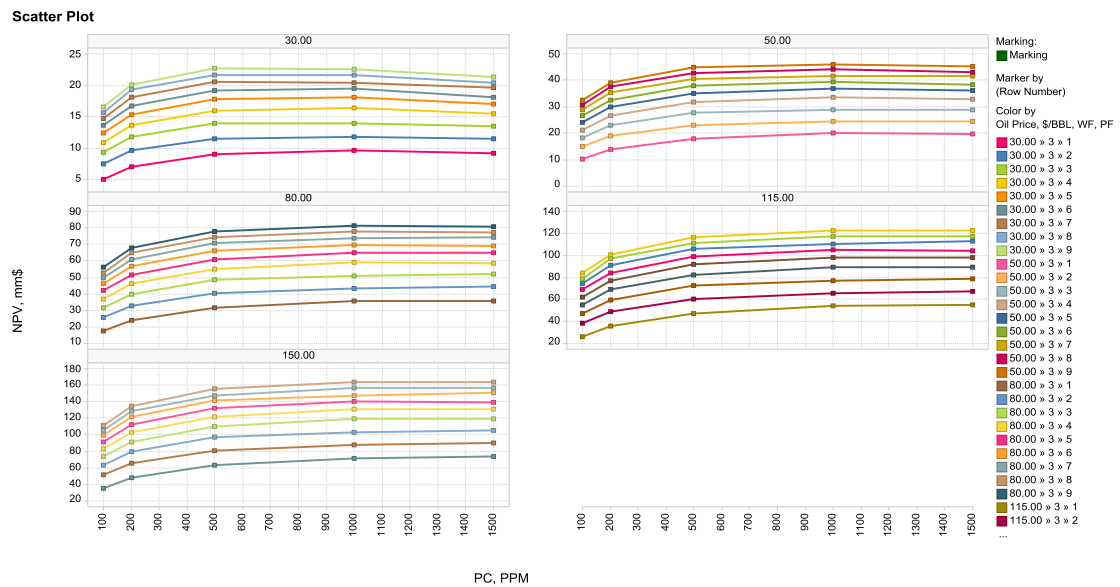


Figure 4.7 Net present value vs. polymer concentrations at different oil prices when the polymer is injected after 3 years of waterflooding; each graph is for a different oil price (\$30, \$50, \$80, \$115, \$150/bbl). On the x-axis is polymer concentration, on the y-axis is NPV. Each line is for a different number of years of polymer flooding (1-9).

The results suggest that once infrastructure is in place, longer periods of polymer injection are better. However, there is little benefit to injecting polymer at concentration greater than 500 ppm, especially if there is a risk of low oil prices.

Figure 4.8 shows the 3D Scatter plot of NPV (on the z axis) as a function of the number of years of polymer flooding (on the x axis) and as a function of the number of years of water flooding before the EOR project (on the y axis), for all polymer concentrations (100, 200, 500, 1000, and 1500 ppm), and all oil prices (\$30, \$50, \$80, \$115, and \$150/bbl) with economic parameters set as follows: IOPC \$8/bbl; WIC \$1/bbl; WPC \$1/bbl; PC 1\$/lb; IPPC \$0/bbl; IPIC \$0.25/bbl. The data shown here is plotted with the Spotfire (TM) software. The observations made include:

- Highest NPV occurs where we have the shortest period of water flooding and longest period of polymer flooding; this is true for all polymer concentrations and all oil prices.
- At this relatively low polymer cost (PC = \$1/lb) the highest NPV is achieved with the highest polymer concentrations
- The later the start in polymer flooding, the lower the NPV

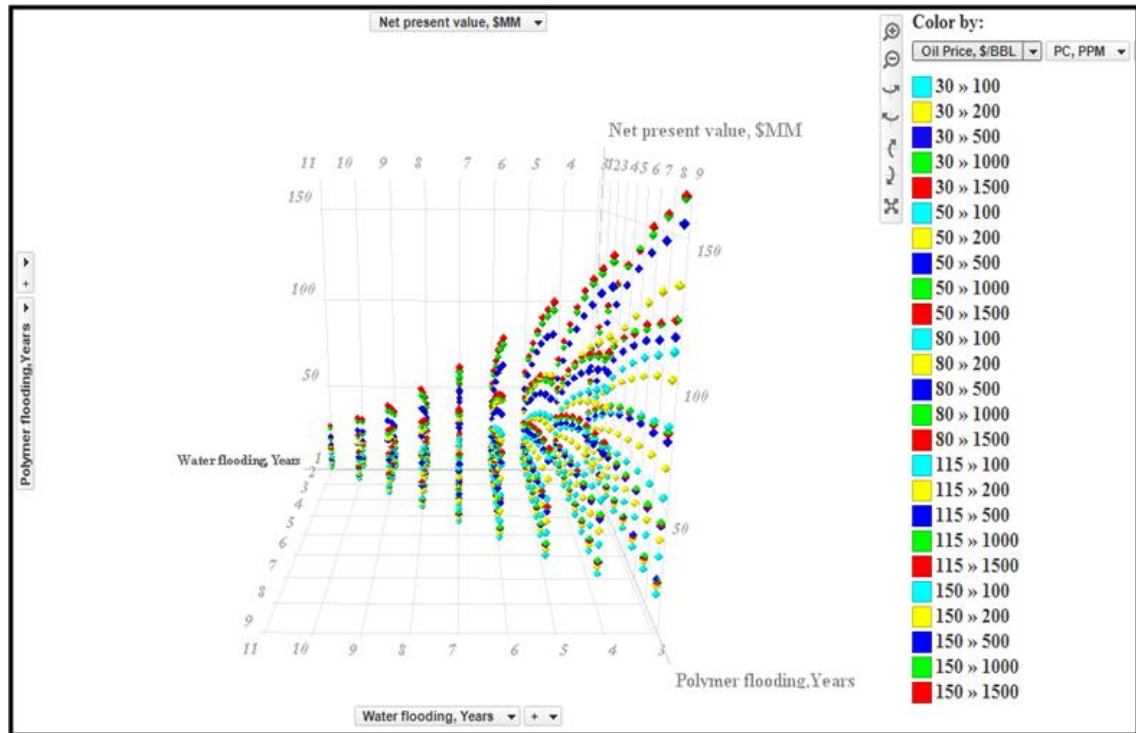


Figure 4.8 3D Scatter plot of NPV vs. number of years of polymer flooding (PF), and number of years of water flooding (WF) for polymer concentrations in range 100, 200, 500, 1000, and 1500 ppm, and oil prices in range \$30, \$50, \$80, \$115, and \$150/bbl

Figure 4.9 shows the relation between net present value and polymer concentration at oil price of \$30/bbl with economic parameters set as follows: WF 3 years; IOPC \$8/bbl; WIC \$1/bbl; WPC \$1/bbl; PC \$4/lb; IPPC \$0/bbl; IPIC \$0.25/bbl. The observations we make from this graph are as follows:

- With a polymer cost increase to \$4/lb, the optimum polymer concentration reduces to 500 ppm.
- NPV increased with increased polymer concentration from 100 to 500 ppm at the increased polymer cost when the oil price is \$30/bbl.
- NPV decreased with increased polymer concentration from 500 to 1500 ppm at the increased polymer cost when the oil price is \$30/bbl.

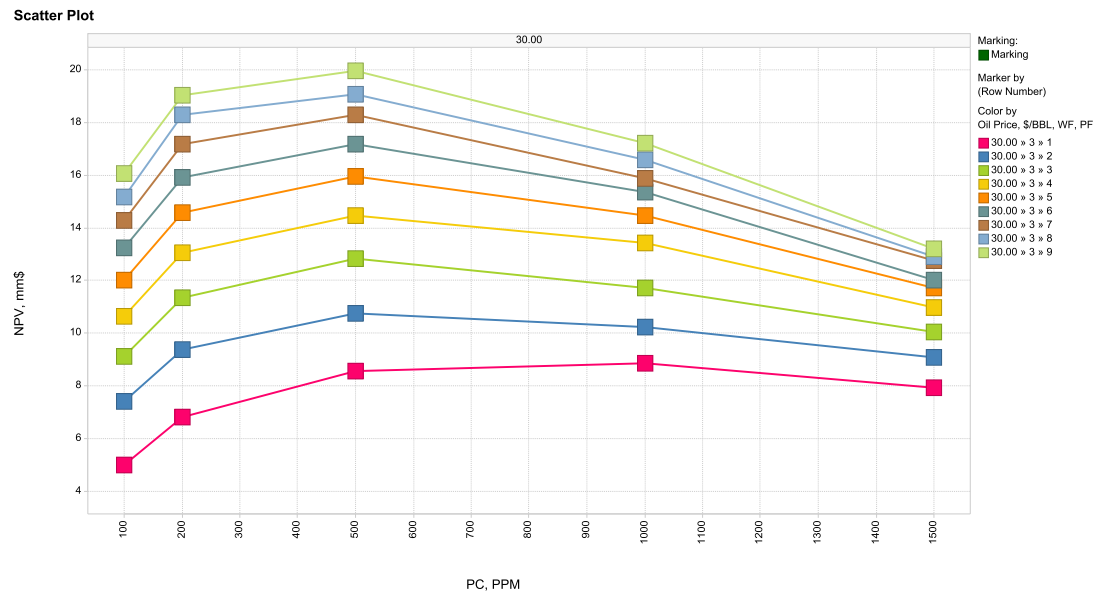


Figure 4.9 Net present value vs. polymer concentrations with polymer cost \$4/lb and \$30/bbl oil price when the polymer is injected for between 1 and 9 years after 3 years of waterflooding

Figure 4.10 shows the relation between net present value and polymer concentration at oil price of \$30/bbl with economic parameters set as follows: WF 3 years; PF 9 years; IOPC \$8/bbl; WIC \$1/bbl; WPC \$1/bbl; PC \$1-\$4/lb; IPPC \$0/bbl; IPIC \$0.25/bbl).

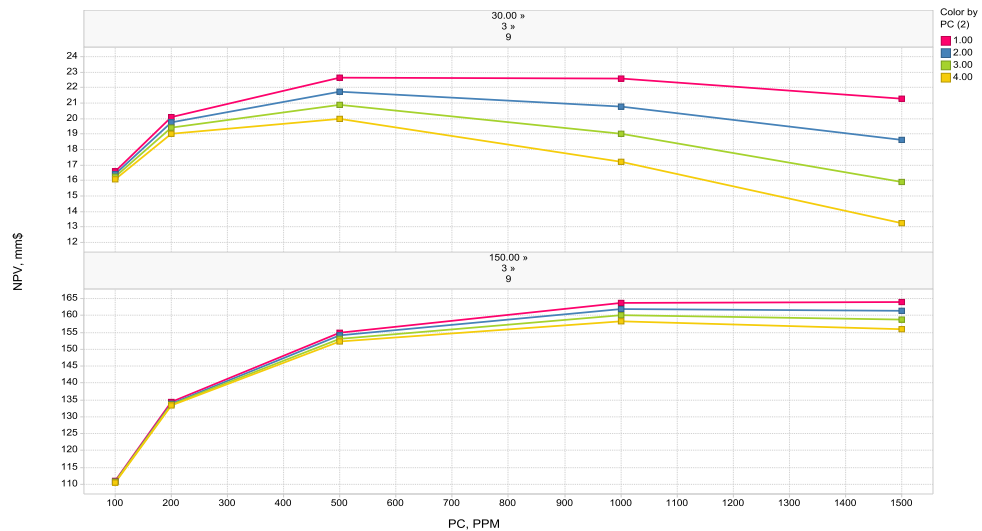


Figure 4.10 Net present value vs. polymer concentrations with polymer cost (1-4 \$/lb) and \$30/bbl oil price when the polymer injected for 9 years after 3 years of waterflooding

Here, we conclude that:

- More significantly, at \$30/bbl oil price the NPV decreases with increasing polymer concentration for concentration above 500 ppm, especially at higher polymer costs, whereas at \$150/bbl, the NPV continues to increase as polymer concentration is increased.
- NPV decreased with increased polymer cost (PC) at both an oil price of \$30/bbl and also at \$150/bbl. However, at \$30/bbl the relative impact of the polymer cost is more evident.

Figure 4.11 shows the probability distribution of net present values at oil price of \$30 and different polymer concentrations of 100, 200, 500, 1000, and 1500 ppm with economic parameters set as follows: WF 3 years; IOPC \$8/bbl; WIC \$1/bbl; WPC \$1/bbl; PC \$4/lb; IPPC \$0/bbl; IPIC \$0.25/bbl. We note that the standard deviation initially increases with polymer concentration, with slight attenuation from 1000 to 1500ppm.

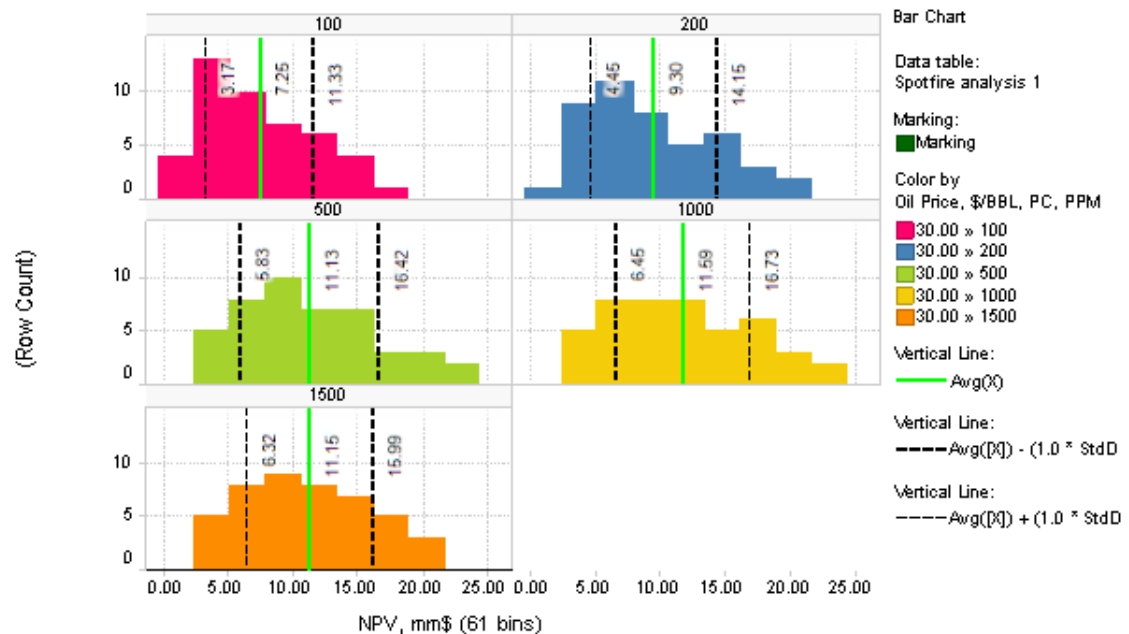


Figure 4.11 Probability distribution of net present value at different polymer concentration of 100, 200, 500, 1000, and 1500 ppm and \$30/bbl oil price

Figure 4.12 shows the probability distribution of net present values at oil price of \$150/bbl and the different polymer concentrations of 100, 200, 500, 1000, and 1500 ppm with economic parameters set as follows: WF 3 years; IOPC \$8/bbl; WIC \$1/bbl;

WPC \$1/bbl; PC \$4/lb; IPPC \$0/bbl; IPIC \$0.25/bbl. Again, we note that the standard deviation initially increases with polymer concentration, with slight attenuation from 1000 to 1500ppm.

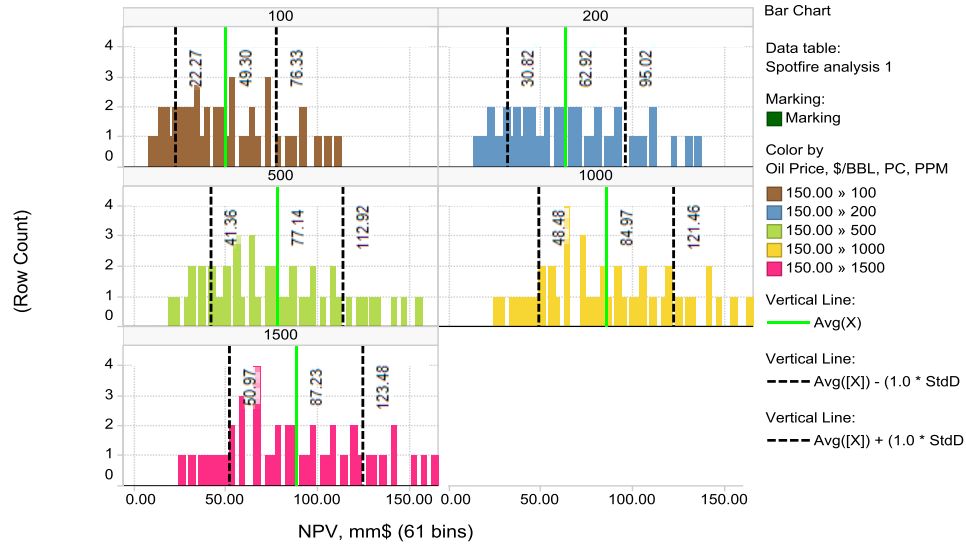


Figure 4.12 Probability distribution of net present value at different polymer concentration of 100, 200, 500, 1000, and 1500 ppm and \$150/bbl oil price

4.3 Discussion

In this chapter the methodology has been developed using a synthetic model by conducting an economic analysis and the results suggest that once infrastructure is in place, longer periods of polymer injection are better. However, there is little benefit to injecting polymer at concentration greater than 500 ppm, especially if there is a risk of low oil prices. The earlier the start in injecting polymer in the life of the project, the better it is with regard to oil recovery comparing and NPV.

The result of the infill well drilling option in the simple synthetic model showed no significant increase in oil recovery for all timing of drilling the new wells. Thus infill well drilling would never be a viable option in this specific scenario, and so no further economic evaluation was carried out for infill well drilling in this chapter.

The results presented here apply to this system only. In the two next chapters we will consider other systems, and although applying the same methodology, may arrive at quite different conclusions.

CHAPTER 5: APPLICATION OF NEW DECISION MAKING TECHNIQUE TO AN OFFSHORE FIELD

This study has focused on the development of a method to test the economic viability of Enhanced Oil Recovery (EOR) versus infill well drilling where the challenge is to compare polymer flooding scenarios with infill well drilling scenarios, not just based on incremental recovery, but on Net Present Value (NPV) as well.

In Chapter 3 the method was developed to address polymer flooding, and it has been applied to a synthetic scenario with constant economic parameters, which has demonstrated the impact that oil price can have on the decision making process.

In Chapter 4 the method was then applied and tested with varied operational and economic parameters to investigate the impact in delaying the start of polymer flooding to identify whether it is better to start polymer flooding earlier or later in the life of the project. Consideration was also given to the optimum polymer concentration, and the impact that factors such as oil price and polymer cost have on this decision. Due to the large number of combined reservoir engineering and economic scenarios, Monte Carlo Simulation (MCS) and advanced analysis of large data sets and the resulting probability distributions had to be developed.

In this chapter the methodology is applied to an offshore field where the choice has already been made to drill infill wells, but where the objective is to test the robustness of the method against a conventional decision making process for which there is historical data. This was done by performing calculations that compare the infill well scenario chosen with a range of polymer flooding scenarios that could have been selected instead, to identify whether or not the choice to drill infill wells was indeed the optimum choice from an economic perspective.

5.1 Arbroath Field Overview

The Arbroath field studied in this chapter is located in UK Continental Shelf blocks 22/17 and 22/18 (Figure 5.1). The field was discovered in 1969 and first oil was produced in 1990. The oil is 38° API, and production is from the Palaeocene Forties turbidite sandstone. A 4D seismic survey was shot in 2000, using a survey from 1993 as the baseline, Stearn (2003).

In 2006 there was a re-appraisal of the 1993 and 2000 4D seismic data over the field. This included a petrophysical review that re-worked the log database in preparation for identifying infill drilling targets.

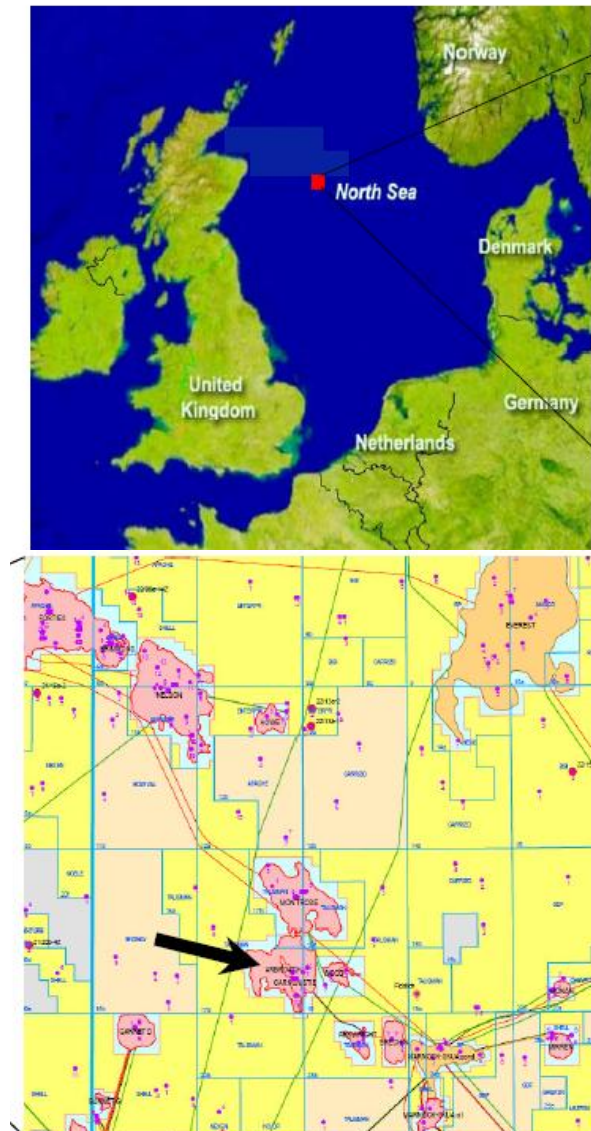


Figure 5.1 Location map of Arbroath field

5.2 Structure

The Montrose, Arbroath and Arkwright Fields flank the eastern margin of the Forties Montrose high, Crawford et al. (1991).

5.3 Stratigraphy

The sandstone forms the main reservoir succession in the Montrose, Arbroath and Arkwright Fields, and is sealed by mudstone. The Forties sequence is characterized by fine to medium grained sandstone interbedded with dark grey siltstone and mudstone, Crawford et al. (1991).

5.4 Trap

The fields comprise separate four way anticline structures, sealed by mudstone of the Sele formation. A relief in excess of 200 ft that has been expanded as a result of differential compaction, Crawford et al. (1991).

5.5 Arbroath Field data summary

Table 5.1 shows Arbroath Field data summary

| Field Name | Arbroath | Units | Notes |
|--------------------------------------|--|---------|-----------------------|
| Discovered | 1969 | | |
| Trap | | | |
| Type | Domal Antiform | | |
| Depth of crest | 8030 | ft ss | |
| Lowest closing counter | 8250 | ft | |
| OWC | 8250 | ft | tilted |
| Oil column | 220 | ft | |
| Pay zone | | | |
| Formation | Forties | | |
| Age | Palaeocene | | |
| Cross thickness average (range) | 330 (260-440) | ft | |
| Net/Gross | 0.5 (0.3-0.8) | ft | |
| Porosity average (range) | 24 (3-30) | % | |
| Permeability average (range) | 80 (1-2000) | mD | |
| Petroleum saturation average (range) | 55 (25-65) | % | |
| Petroleum | | | |
| Oil density | 0.28 | g/cc | |
| Oil gravity | 38-42 | API | |
| Viscosity | 0.4 | cp | at original condition |
| Bubble point | 1991 | psig | |
| Gas/Oil ratio | 490 | SCF/BBL | |
| Formation volume factor | 1.327 | RB/STB | |
| Formation water | | | |
| Salinity | 135,000 | Mg/l | |
| Resistivity | 0.023 | Ohm m | @ 245 F |
| Field characteristics | | | |
| Area | 7712 | acres | |
| Gross rock volume | 555,000 | Acre ft | |
| Initial pressure | 3700 | psi | @ 8500 ft |
| Temperature | 245 | F | |
| Oil initially in place | 334 | MMBBL | |
| Recovery factor | 51 | % | |
| Drive mechanism | Aquifer drive/gas lift | | |
| Recoverable oil | 170 | MMBBL | |
| Production | | | |
| Start-up date | 1990 | | |
| Production rate plateau oil | 42,000 | BOPD | |
| Number/type of well | 12 production wells 8 injection wells | | |

Table 5.1 Arbroath Field data summary Crawford et al. (1991)

5.6 Infill Drilling Location Identification

In the paper by Helix (2008) they discussed the location of the infill well drilling and were able to identify what they considered to be optimal locations for new wells.

Final Fluid and Lithology impedance volumes were interpreted to predict potential infill drilling targets and areas of by-passed pay within the Arbroath reservoir. RMS amplitude extractions were taken around the top reservoir horizon from LI and from the 1993 and 2000 vintage FI volumes. A 4D difference map was constructed from the two FI extractions (Figure 5.2). The analysis clearly shows the extent of both reservoir sand and hydrocarbon fill within the Arbroath field. The 4D difference map shows extensive areas of fluid production, with the greatest 4D difference being observed around water injector wells.

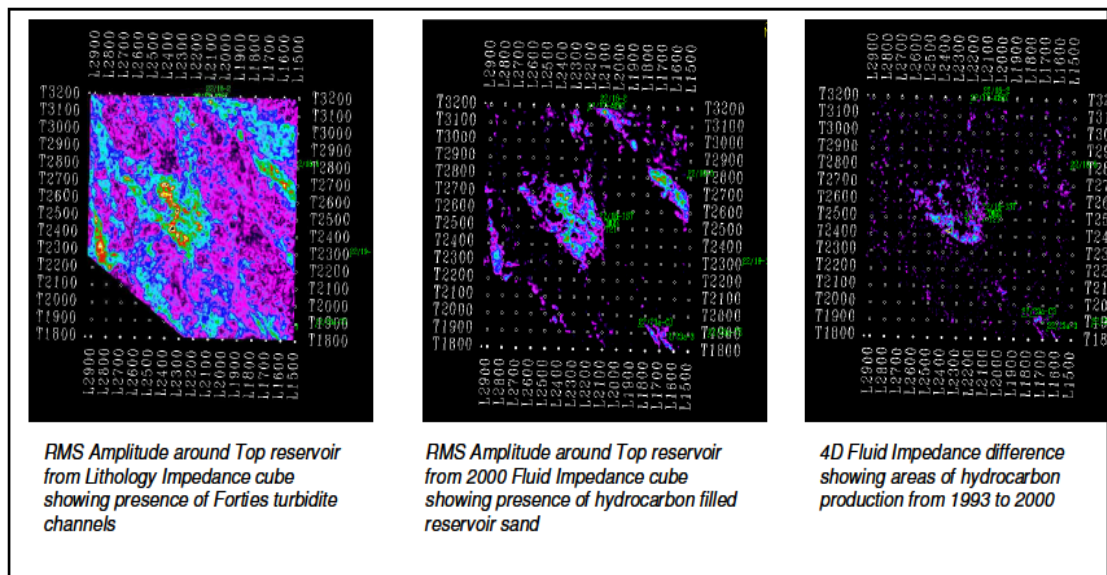


Figure 5.2- RMS horizon amplitude extractions from LI, FI and 4D FI volumes

5.7 System Description

A full field model for Arbroath was developed in 1996 by BP (Figure 5.7). The number of cells in X direction is 52; the number of cells in Y direction is 62, and the number of cells in Z direction is 13. The total number of cells is 41912 Appendix (A2). Initial conditions are shown in table (Table 5.2).

| | |
|-----------------------|------|
| Datum Depth, ft | 8150 |
| Pressure, Psi | 3680 |
| Oil water contact, ft | 8265 |

Table 5.2- Arbroath Field data

The same analysis as was carried out for the synthetic model is here presented for the Arbroath Field example. Figure 5.3 shows the relative permeability curves, and Figure 5.4 the fractional flow curves for waterflooding and for polymer flooding.

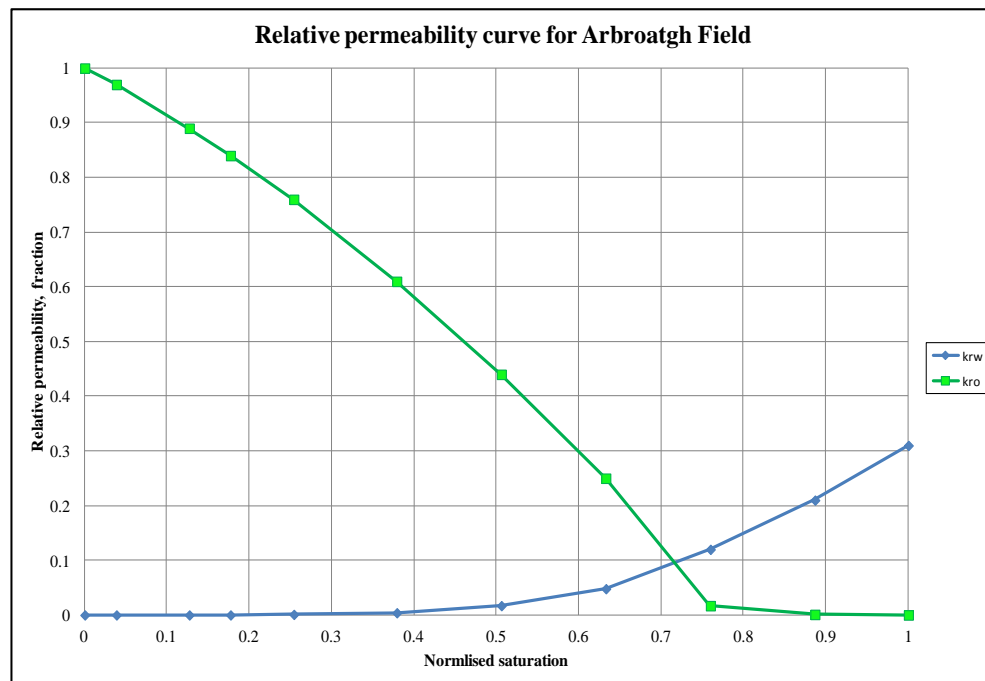


Figure 5.3- Typical normalized relative permeability curves for the Arbroath Field

The results of the same fractional flow analysis are presented in Table 5.3 and Table 5.4 shows the resulting water saturation profiles that were calculated.

| | case | S_{wbt} | Reservoir | Surface | $\overline{\overline{S}}_{wbt}$ | $N_{pdpt} (PV)$ |
|---------------|----------|-----------|-----------|------------|---------------------------------|-----------------|
| | | | f_{wbt} | f_{wsbt} | | |
| 0.4 cP | WF | 0.79 | 0.96 | 0.82 | 0.83 | 0.79 |
| Oil viscosity | 1000 ppm | 0.94 | 0.95 | 0.83 | 0.99 | 0.95 |
| 50 cP | WF | 0.51 | 0.87 | 0.91 | 0.59 | 0.55 |
| Oil viscosity | 1000 ppm | 0.77 | 0.98 | 0.81 | 0.7 | 0.66 |

Table 5.3- Oil recoveries and saturation at breakthrough for Buckley-Leverett method

| | case | S_{wf} | μ_o/μ_w | $K_{rw}(S_{wf})$ | $K_{ro}(S_{wf})$ | M_s | M |
|-------------------------|----------|----------|---------------|------------------|------------------|-------|------|
| 0.4 cP Oil viscosity | WF | 0.79 | 1.2 | 0.15 | 0.01 | 0.23 | 0.45 |
| | 1000 ppm | 0.94 | 0.03 | 0.26 | 0.001 | 0.01 | 0.01 |
| 50 cP Oil viscosity | WF | 0.51 | 151.5 | 0.02 | 0.44 | 4.13 | 55.9 |
| | 1000 ppm | 0.77 | 3.6 | 0.13 | 0.017 | 0.57 | 1.3 |

Table 5.4- Values of the shock front and end point relative permeabilities calculated using fractional flow.

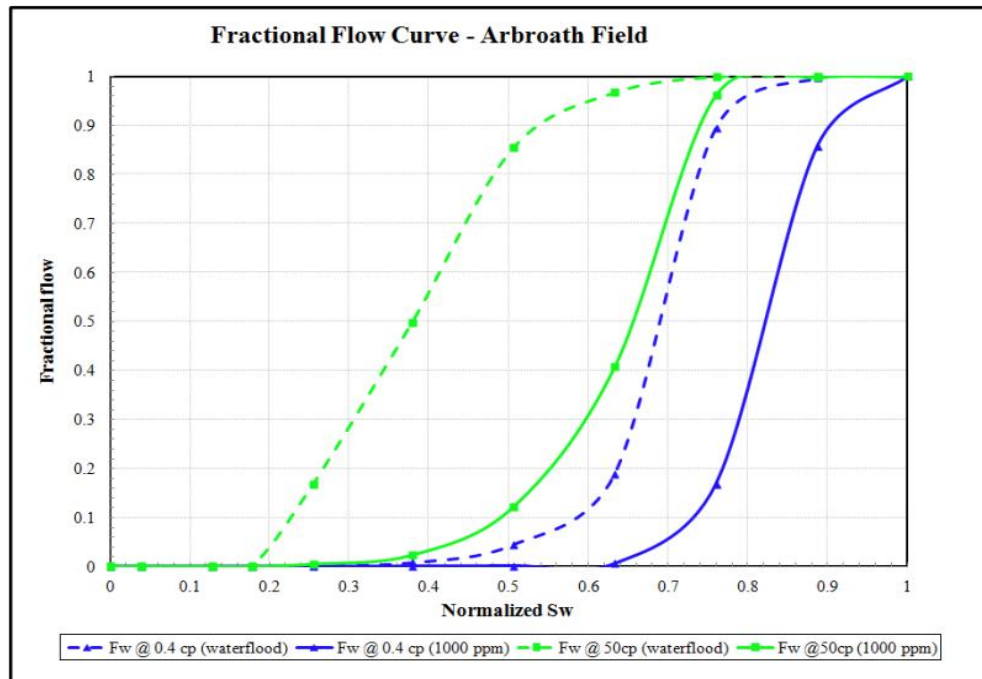


Figure 5.4- Typical normalized plots of fractional flow curve for Arbroath Field

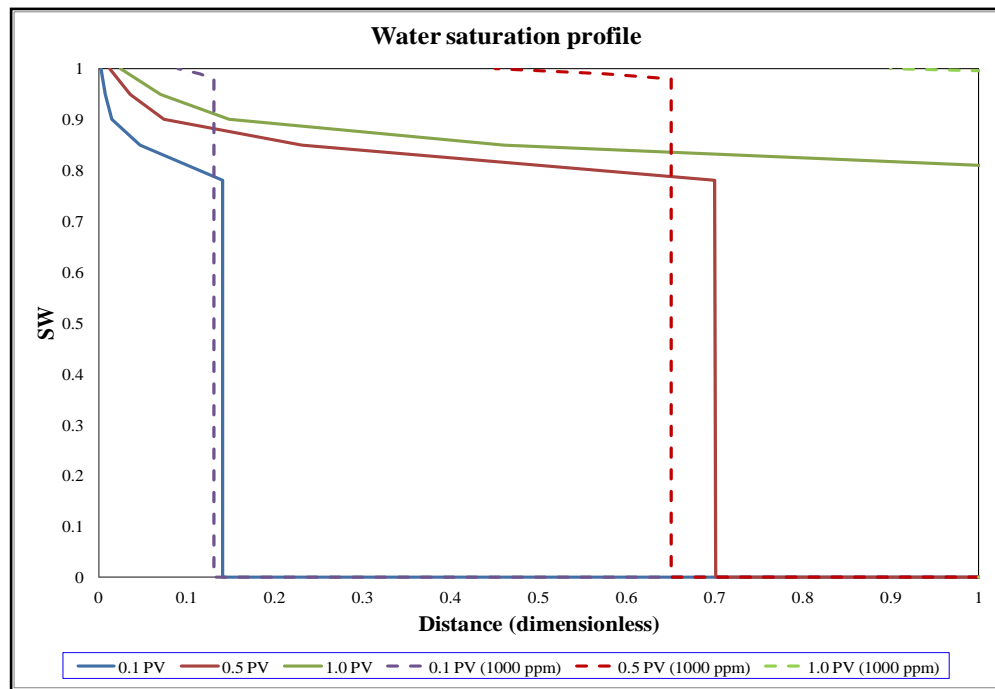


Figure 5.5- Water saturation profile (oil viscosity of 0.4 cP) as a function of distance and time

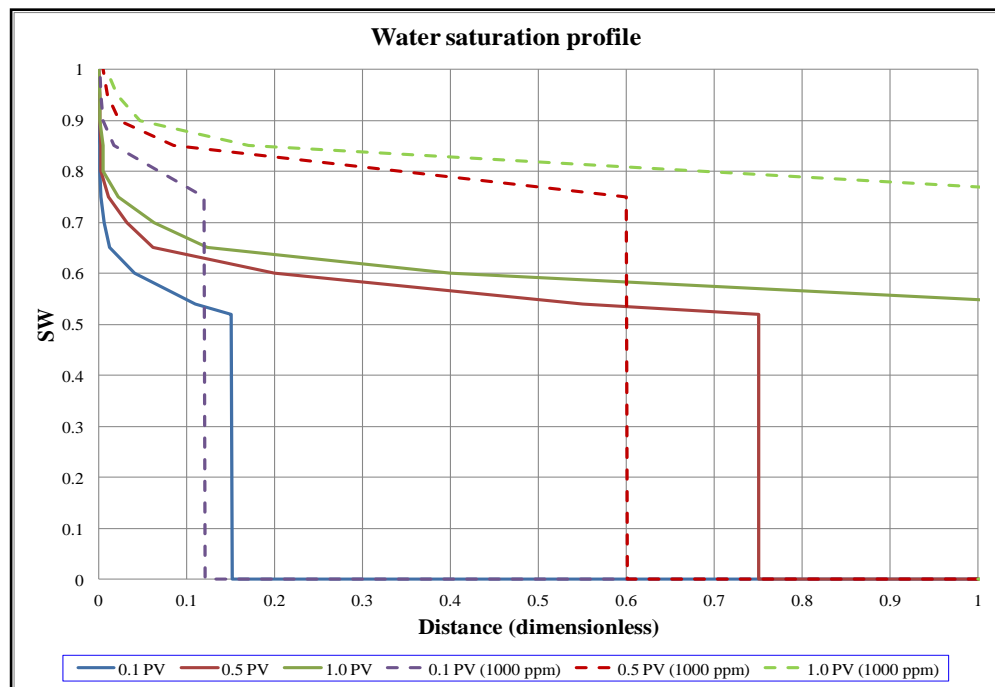


Figure 5.6- Water saturation profile (oil viscosity increased by a factor of 50) as a function of distance and time

This analysis indicates that for the 0.4 cP oil in this field, waterflooding results in a favourable mobility ratio, and thus this field would not be a strong candidate for polymer flooding. A comparison has been calculated for what would be the case if the oil viscosity were increased by a factor of 50 – thereby increasing the mobility ratio by a factor of 50. Under these circumstances, use of polymer has a greater impact on improving the sweep efficiency, as can be seen from Figure 5.5. The reason the high viscosity oil is analysed here is to demonstrate the greater impact that polymer flooding has when the mobility ratio is higher. However, the reservoir simulation analysis was conducted with the actual field oil viscosity, and thus it is to be anticipated that the improvement in recover and sweep efficiency when using polymer flooding would only be marginal, as Figure 5.4 suggests.

Figure 5.7 demonstrates the field fluid saturation during water flooding and also shows the location of the total of twenty producing and injector wells.

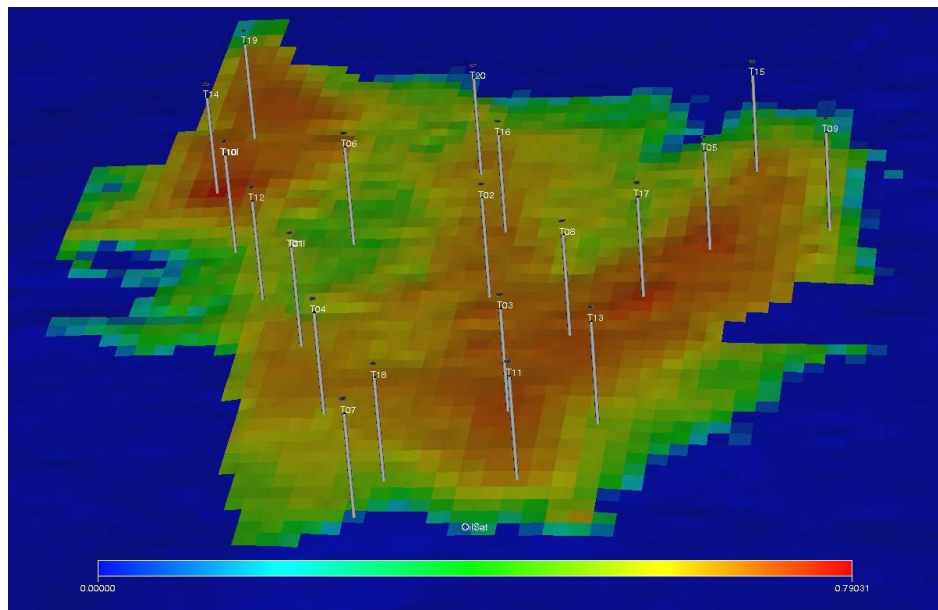


Figure 5.7 Arbroath field model (at stage of waterflood)

Figure 5.8 demonstrated the end of stage one (water flooding) and also shows the location of the total of twenty producing and injector wells and the new four infill well drilling Tab, Tac, Tad and TAf .

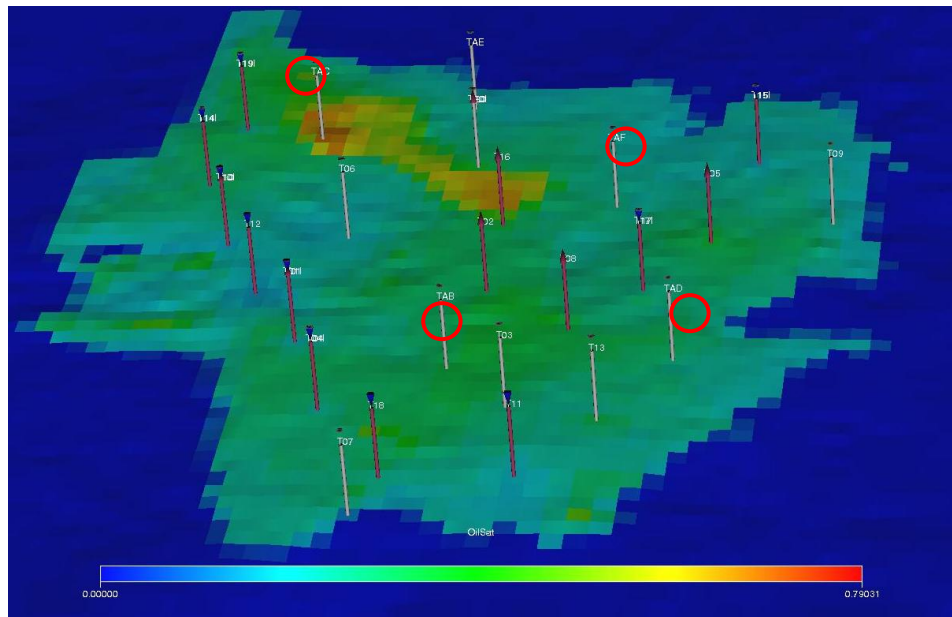


Figure 5.8 Arbroath field model (stage one of waterflooding end)

Figure 5.9 shows the start of stage two (Infill well drilling) and also shows the location of the new four infill well drilling Tab, Tac, Tad and Taf .

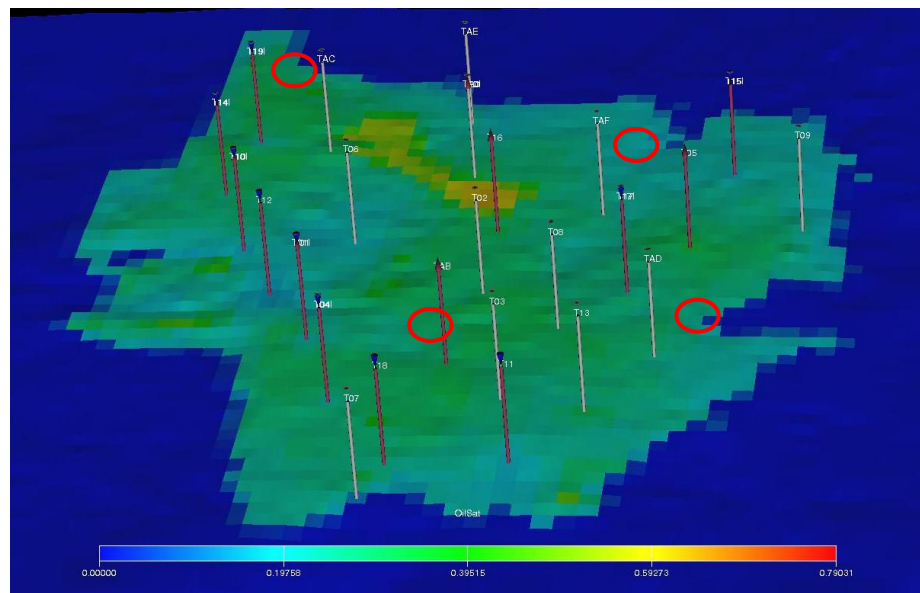


Figure 5.9 Arbroath field model (stage two – 4 Infill well included)

5.8 Infill well drilling (Case 1- low viscosity oil)

5.8.1 Reservoir simulation 1 for infill well drilling

The first set of calculations assumes the actual Arbroath Field oil viscosity of 0.4 cP.

Four Infill wells were drilled and put on production (TAB, TAC, TAD, and TAF) in 1999 after eight years of water flooding. (Table 5.5) shows the sensitivity scenarios for the infill wells to find out whether the decision that has been taking was the right choice.

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 |
|---|------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|
| Years | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
| Number of new wells drilled and completed this year | 4 | | | | | | | | | | | | | | | | | | |
| Name of wells decommissioned | | | | | | | TAD | | | | | | | | TAF | | | | |
| Number of wells decommissioned | | | | | | | 1 | | | | | | | | 1 | | | | |
| Cumulative number of new wells (1) | 4 | 4 | 4 | 4 | 4 | 4 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 2 | 2 | 2 | 2 | 2 |
| TAF-Shut (2) | 3 | 3 | 3 | 3 | 3 | 3 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| TAD-Shut (3) | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 2 | 2 | 2 | 2 | 2 |
| TAC-Shut (4) | 3 | 3 | 3 | 3 | 3 | 3 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 1 | 1 | 1 | 1 | 1 |
| TAB-Shut (5) | 3 | 3 | 3 | 3 | 3 | 3 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 1 | 1 | 1 | 1 | 1 |

Table 5.5-Infill well drilling sensitivities

The procedure for the reservoir simulation 1 calculations is as follows:

- 5 sensitivities have been run with 4 infill wells drilled (Table 5.5).
- Two contiguous stages (total time up to 20 years):
 - Stage 1: Water flood (1991 till 1999)
 - Stage 2: Infill well drilling (1999)
- The following output is generated
 - Field oil production total (FOPT)
 - Field water production total (FWPT)
 - Field water injection total (FWIT)

Figure 5.10 shows the cumulative of oil production per year for comparison of different scenarios of the new infill well drilling (TAB, TAC, TAD, and TAF) compared to waterflooding scenario.

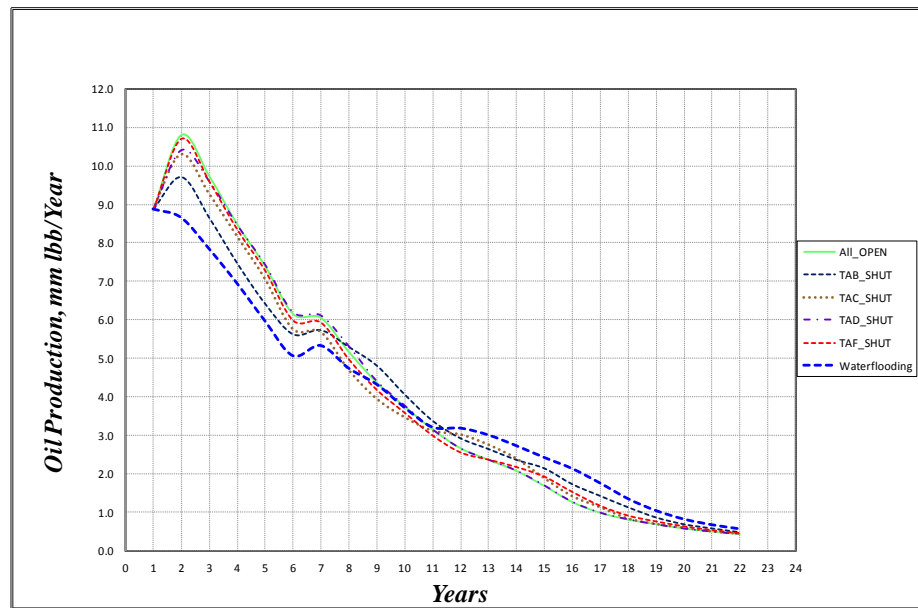


Figure 5.10 Arbroath oil production for different sensitivities of infill well drilling

Figure 5.11 shows the field oil production total of the new infill well drilling (TAB, TAC, TAD, and TAF) compared to waterflooding scenario.

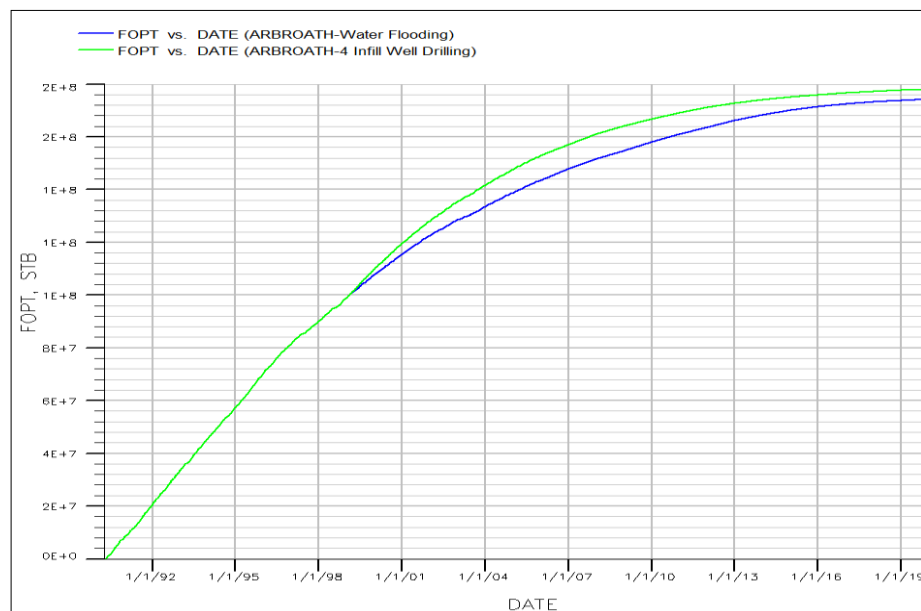


Figure 5.11 Field oil production total between water flooding & infill well drilling

Figure 5.12 shows the field water injection total of the new infill well drilling (TAB, TAC, TAD, and TAF) compared to waterflooding scenario.

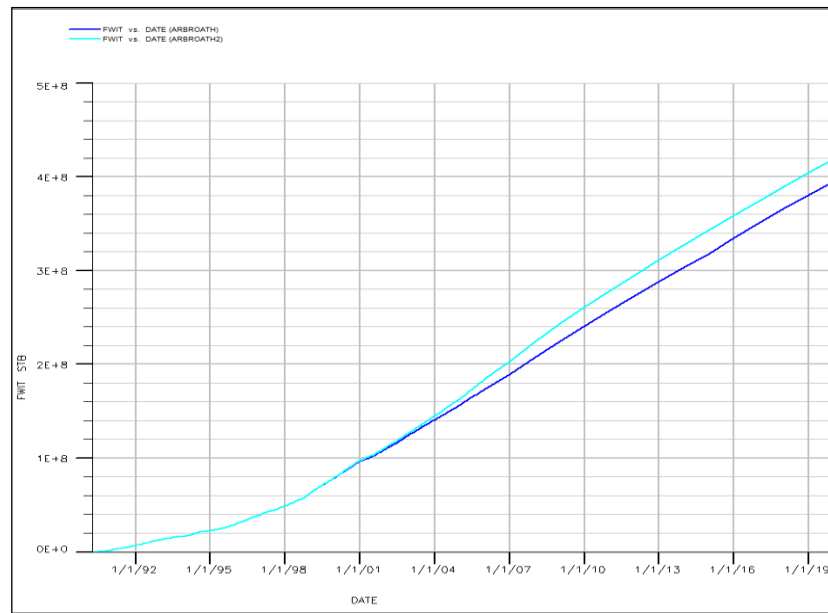


Figure 5.12 Field water injection total between water flooding & infill well drilling

Figure 5.13 shows the field water production total of the new infill well drilling (TAB, TAC, TAD, and TAF) compared to waterflooding scenario.

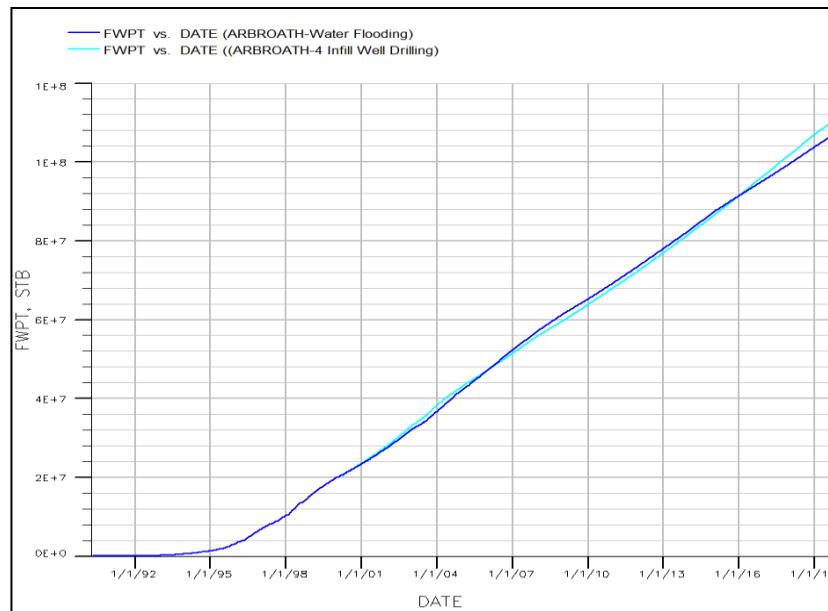


Figure 5.13 Field water Production total between water flooding & infill well drilling

5.8.2 Economic model 1 for infill well drilling

The procedure for the economic model is as follows:

- Input
 - Results of reservoir simulation calculations (identified above)
 - Economic parameters: infill well drilling cost, incremental well operating expenses, additional capital expenditure, oil price, incremental oil production cost (IOPC), water injection cost (WIC), water production cost (WPC).
- Output
 - Incremental cash flow (ICF)
 - Derived performance measures
 - Net present value (NPV)
 - Maximum capital outlay (MCO)

5.8.3 Sensitivity and Risk Analysis for infill well drilling

The variables range that are used to assess the design, using project profitability measures as the decision making tool in the economic model of the infill well drilling scenarios are given in Table 5.6.

| EOR technique | Waterflooding | Infill well drilling |
|---|----------------------|-----------------------------|
| Duration of water flooding, years | 1-20 | 8-20 |
| New infill well drilling | - | 4 |
| Well capital cost, mm\$/well | - | 10-15-20 |
| Well Operating cost, mm\$/yr | - | 1-2-3 |
| Additional capital expenditure, mm\$ | - | - |
| Oil price, \$/bbl | 30-50-80-115-150 | 30-50-80-115-150 |
| Incremental oil production cost, \$/bbl | 8-10-12 | 8-10-12 |
| Water injection cost, \$/bbl | 1-2-8 | 1-2-8 |
| Water production cost, \$/bbl | 1-2-3 | 1-2-3 |

Table 5.6-Ranges used for economic parameters for the infill well drilling sensitivities

Figure 5.14 shows the discounted cash flow (DCF) by years for all the five scenarios of the infill wells drilling at discount rate of 10%, \$50 / bbl oil price, incremental oil price cost \$8 /bbl, water injection cost \$2 /bbl, water production cost \$2 /bbl, well operating cost 1mm\$, and well capital cost 10mm\$. It is unclear what will be the best scenario that will give the highest Net Present Value (NPV). However, Figure 5.15 would give us a clear view of the best scenario in this case.

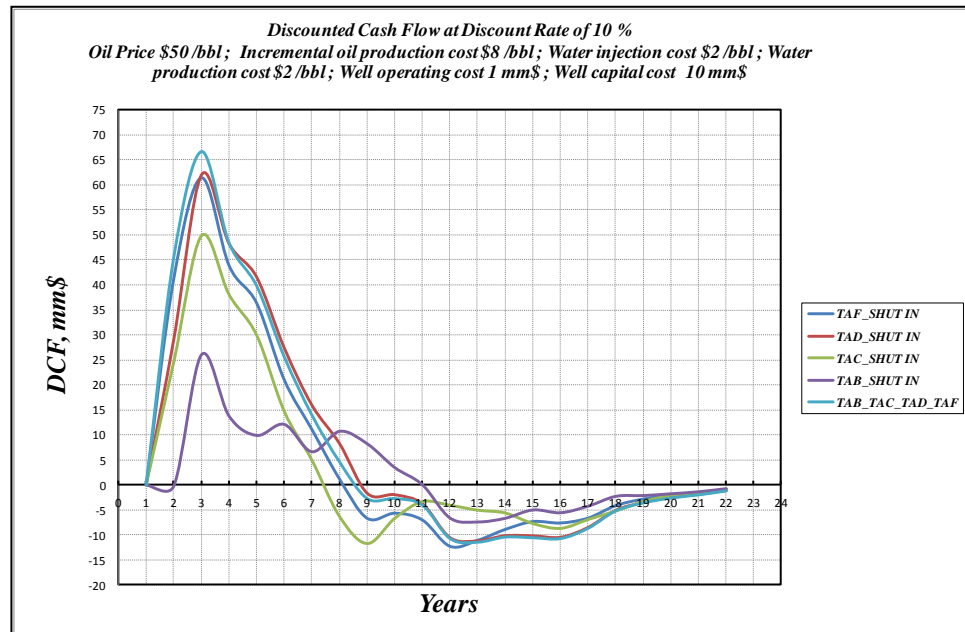


Figure 5.14 Discounted cash flow (DCF) of infill well drilling for different sensitivities

Figure 5.15 shows the cumulative discounted cash flow (DCF) by years for all the five scenarios of the infill wells drilling at discount rate of 10%, \$50 / bbl oil price, incremental oil price cost \$8 /bbl, water injection cost \$2 /bbl, water production cost \$2 /bbl, well operating cost 1mm\$, and well capital cost 10mm\$. As can be seen the highest Net Present Value (NPV) occurred with all the infill wells open.

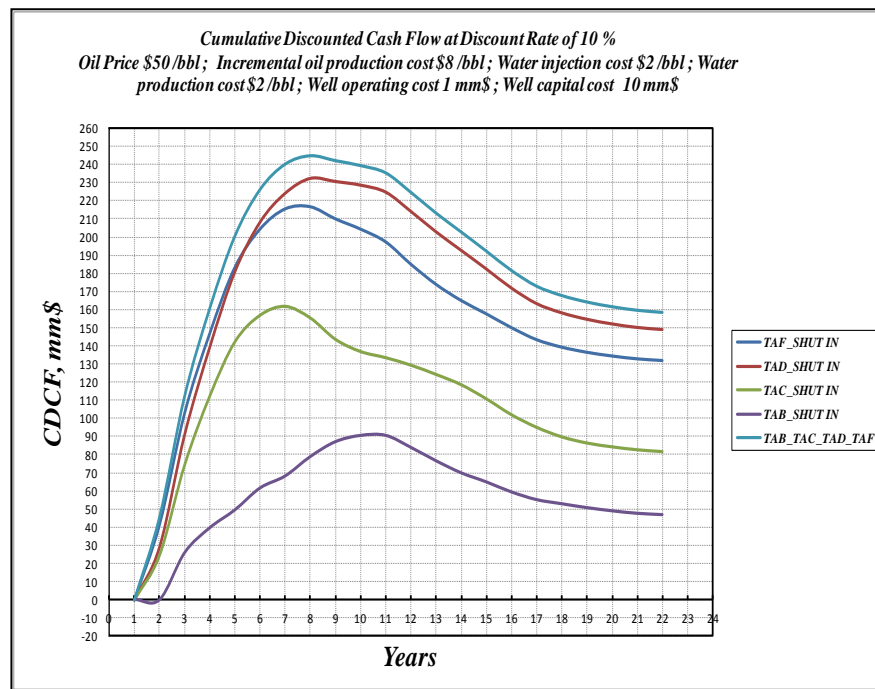


Figure 5.15 Cumulative discounted cash flow (CDCF) of infill well drilling of different sensitivities

The relation between Net Present Value (NPV) versus different oil prices of \$30 /bbl, \$50 /bbl, \$80 /bbl, \$115 /bbl, and \$150 /bbl respectively, for five scenarios of the infill wells drilling are illustrated in Figure 5.16, with discount rate of 10%, incremental oil price cost \$8 /bbl, water injection cost \$1 /bbl, water production cost \$1 /bbl, well operating cost 1mm\$, and well capital cost 10mm\$. As can be seen the highest Net Present Value (NPV) occurred where all the infill wells are open. The values of the Net Present Value (NPV) for all scenarios are summarised below in Table 5.7.

| Infill wells name | Net Present Value, MM\$ | | | | |
|-------------------|-------------------------|-----------|-----------|------------|------------|
| | \$30 /bbl | \$50 /bbl | \$80 /bbl | \$115 /bbl | \$150 /bbl |
| All-Open | 49.5 | 171.7 | 355.1 | 569.0 | 782.9 |
| TAB-SHUT | 10.2 | 73.7 | 168.9 | 280.1 | 391.2 |
| TAC-SHUT | 28.4 | 110.3 | 233.2 | 376.5 | 519.7 |
| TAD-SHUT | 59.1 | 174.7 | 348.1 | 550.4 | 752.7 |
| TAF-SHUT | 53.6 | 162.5 | 325.8 | 516.4 | 707.1 |

Table 5.7-Net Present Values for the infill well drilling sensitivities at different oil prices

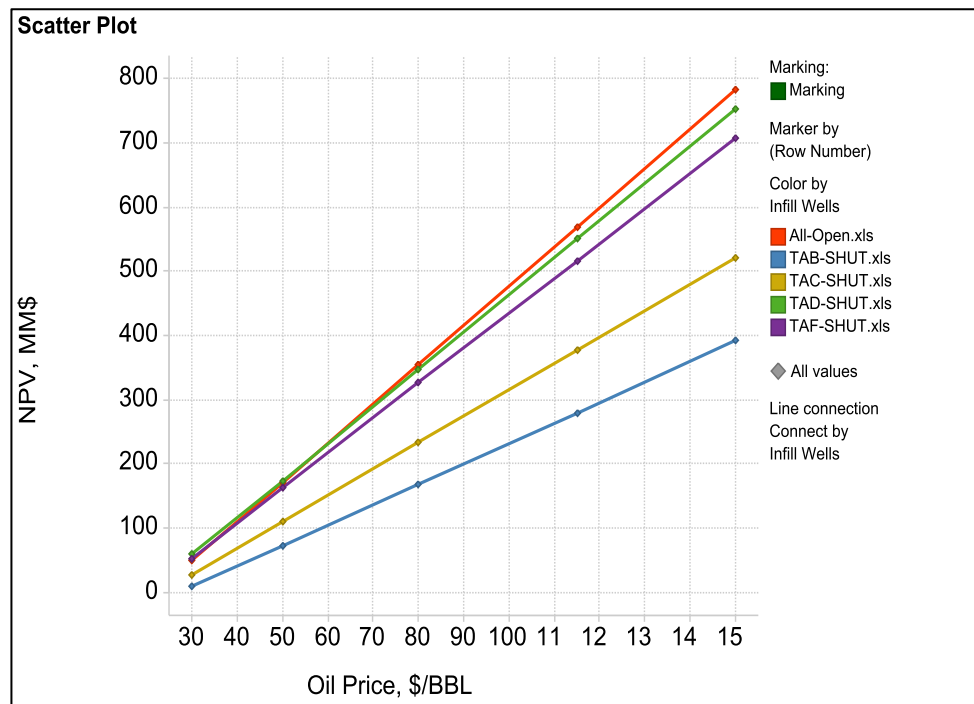


Figure 5.16 Net present value (NPV) versus of different oil prices of \$30 /bbl, \$50 /bbl, \$80 /bbl, \$115 /bbl, and \$150 /bbl of different sensitivities of infill wells drilling

Figure 5.17 shows the probability distribution of Net Present Value (NPV) at different oil prices of \$30 /bbl, \$50 /bbl, \$80 /bbl, \$115 /bbl, and \$150 /bbl for the infill wells scenarios with economic parameters set as follows: discount rate of 10%, incremental oil price cost \$8 /bbl, water injection cost \$1 /bbl, water production cost \$1 /bbl, well operating cost 1mm\$, and well capital cost 10mm\$. We note that the standard deviation increases with increased oil price.

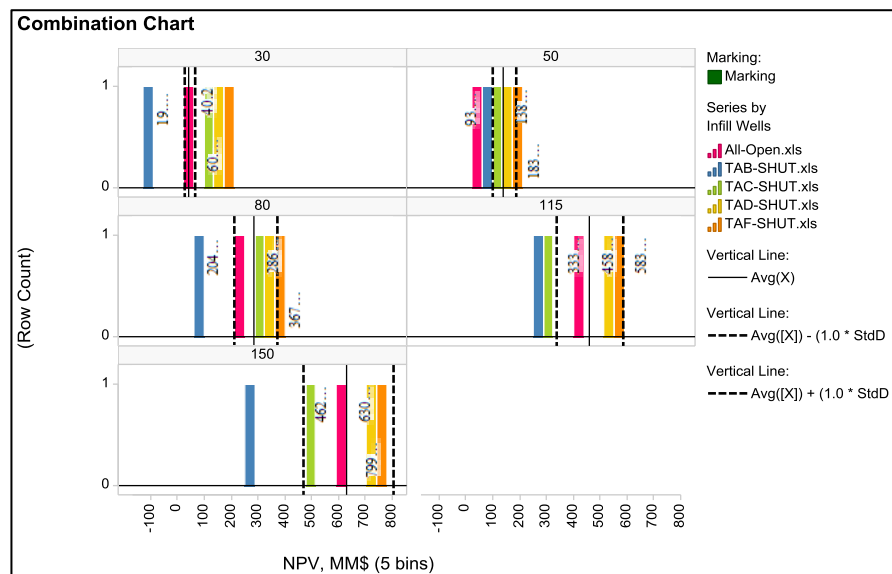


Figure 5.17 Probability distribution of net present value (NPV) at different oil prices of \$30 /bbl, \$50 /bbl, \$80 /bbl, \$115 /bbl, and \$150 /bbl of the infill wells scenarios

Table 5.8 shows the statistical data for infill well drilling sensitivity scenarios which are average net present value, standard deviation, and the probability of loss for each scenario, respectively. There will be no probability of loss (1-NormDist(X, Mean, Stranded Deviation)) in all scenarios when the oil prices are \$80/bbl or higher but we have high probability of loss when the oil price is \$30/bbl.

| Infill wells | Statistics | Oil price \$/BBL | | | | |
|--------------|---------------------|------------------|------|-------|-------|-------|
| | | 30 | 50 | 80 | 115 | 150 |
| All Open | Avg. (NPV), mm\$ | -48.5 | 73.6 | 257.0 | 470.9 | 684.8 |
| | StdDev. (NPV) | 50.5 | 50.5 | 50.5 | 50.5 | 50.5 |
| | Probability loss, % | 83 | 7 | 0.0 | 0.0 | 0.0 |
| TAB-Shut | Avg. (NPV), mm\$ | -53.6 | 9.8 | 105.1 | 216.3 | 327.4 |
| | StdDev. (NPV) | 32.8 | 32.8 | 32.8 | 32.8 | 32.8 |
| | Probability loss, % | 95 | 38 | 0.0 | 0.0 | 0.0 |
| TAC-Shut | Avg. (NPV), mm\$ | -35.9 | 44.9 | 167.7 | 311.0 | 454.3 |
| | StdDev. (NPV) | 30.5 | 30.5 | 30.5 | 30.5 | 30.5 |
| | Probability loss, % | 89 | 7 | 0.0 | 0.0 | 0.0 |
| TAD-Shut | Avg. (NPV), mm\$ | -25.2 | 90.3 | 263.7 | 455.0 | 653.3 |
| | StdDev. (NPV) | 45.8 | 45.8 | 45.8 | 45.8 | 45.8 |
| | Probability loss, % | 71 | 2 | 0.0 | 0.0 | 0.0 |
| TAF-Shut | Avg. (NPV), mm\$ | -28.3 | 80.5 | 243.9 | 434.5 | 625.1 |
| | StdDev. (NPV) | 44.3 | 44.3 | 44.3 | 44.3 | 44.3 |
| | Probability loss, % | 74 | 3 | 0.0 | 0.0 | 0.0 |

Table 5.8 - Infill well drilling average NPV, Standard deviation and the probability of loss at different oil prices

5.9 Polymer flood (case 1- low viscosity oil)

5.9.1 Reservoir simulation 2 for polymer flood

The procedure for the reservoir simulation 2 calculations is as follows:

16 sensitivities have been run with polymer concentrations: 100, 200, 500, and 1000ppm.

- Three contiguous stages (total time up to 20 years):
 - Stage 1: Water flood.
 - Stage 2: Polymer flood.
 - Stage 3: Water flood for up to 10 years, depending on WCT
- Stage 1 commences in 1991 and continuous to 1999.
- Stage 2 lasts between 1 and 10 years.
- The following output is generated
 - Field oil production total (FOPT)
 - Field water production total (FWPT)
 - Field water injection total (FWIT)
 - Field polymer injection total (WCIT)
 - Field polymer production total (WCPT)

The injection rate during the polymer flooding scenarios has been increased from 6000 BWPD during the conventional water flood to 8000 BWPD.

Figure 5.18 & Figure 5.19 show that the field oil production total during the polymer flood scenarios rises slightly higher than during the conventional water flooding when the polymer concentration of 100 and 200 ppm for 1, 2, and 3 years of polymer flood is used, but is lower with 10 years of polymer flooding, and then the model stopped running because the water cut exceeded the 98 %.

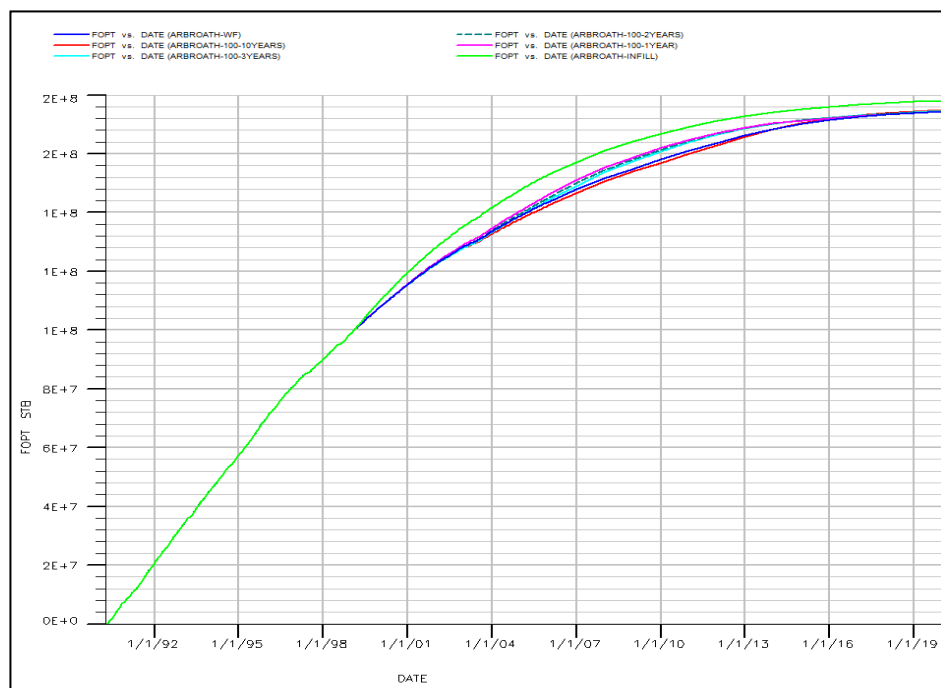


Figure 5.18 Field oil production total for polymer concentration of 100 ppm

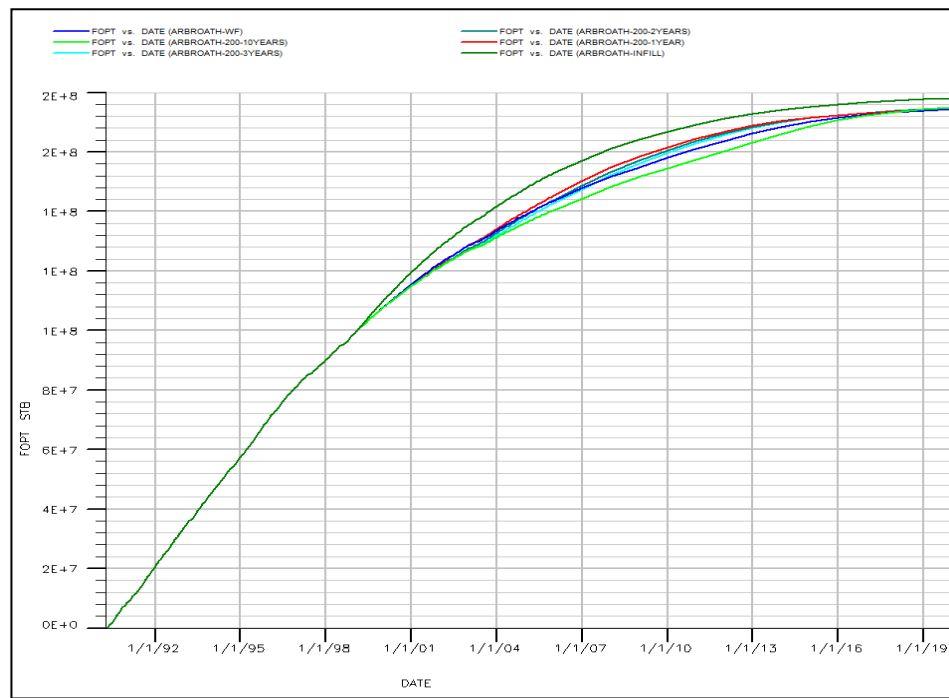


Figure 5.19 Field oil production total for polymer concentration of 200 ppm

Figure 5.20 and Figure 5.21 show the field oil production total during the polymer flood scenarios continues slightly higher than the conventional water flooding when the polymer concentration of 500 and 1000 ppm for 1 year of polymer flood used, but lower with 2, 3, and 10 years of polymer flooding, and then the model stopped from running because of the water cut limitation exceeding 98 %.

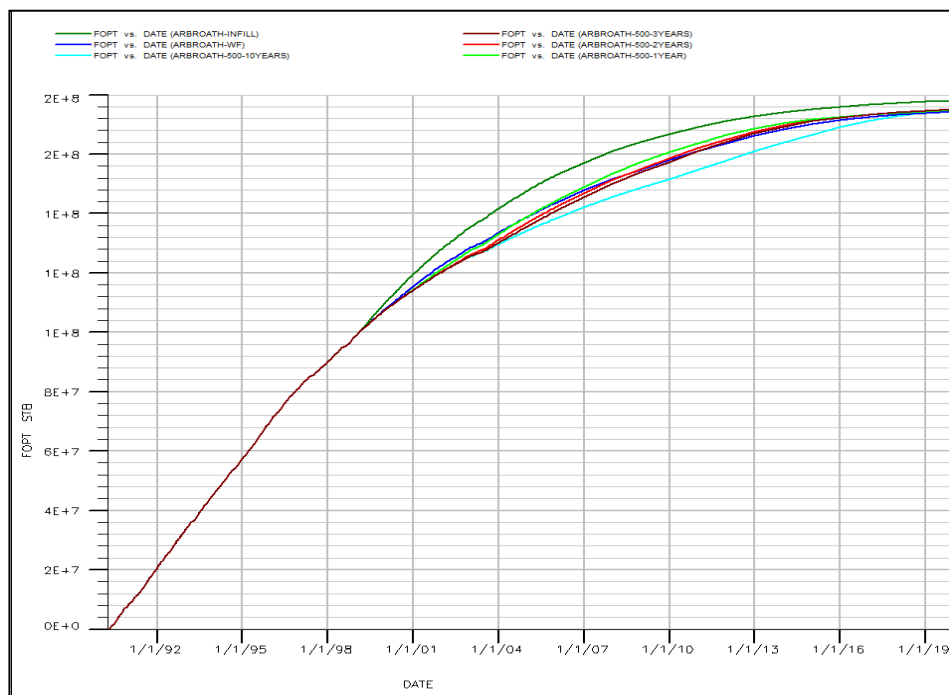


Figure 5.20 Field oil production total for polymer concentration of 500 ppm

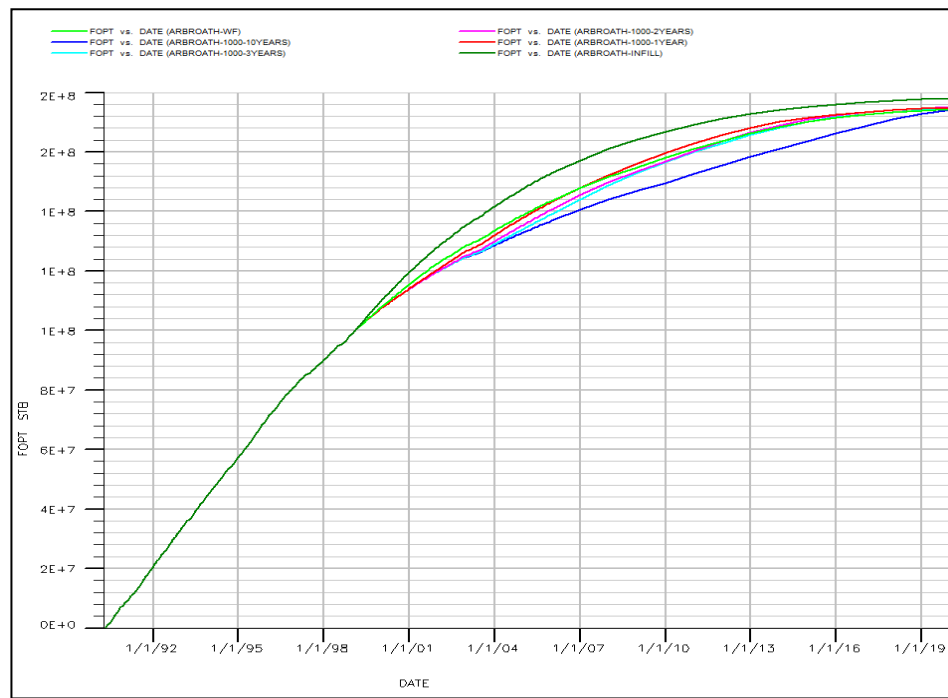


Figure 5.21 Field oil production total for polymer concentration of 1000 ppm

5.9.2 Economic model 2 polymer flooding case 1-low viscosity oil

The procedure for the economic model is as follows:

- Input
 - Results of reservoir simulation calculations (identified above)
 - Economic parameters: Polymer concentration, oil price, incremental oil production cost (IOPC), water injection cost (WIC), water production cost (WPC), polymer cost (PC), incremental polymer production cost (IPPC), incremental polymer injection cost (IPIC).
- Output
 - Incremental cash flow (ICF)
 - Derived performance measures
 - Net present value (NPV)
 - Maximum capital outlay (MCO)

5.9.3 Sensitivity and Risk Analysis for polymer flooding

The ranges of the variables that are used to assess the design, using project profitability measures as the decision making tool in the economic model of the polymer flooding scenarios, are given in Table 5.9.

| EOR technique | Water flooding | Polymer flooding |
|---|------------------|------------------|
| Duration of water flooding, years | 1 to 8 | 1 to 12 |
| Duration of polymer flooding, years | - | 1 -2-3-10 |
| Additional capital expenditure, mm\$ | - | 8-11-18-31 |
| Polymer concentration, ppm | - | 100-200-500-1000 |
| Oil Price, \$/bbl | 30-50-80-115-150 | 30-50-80-115-150 |
| Incremental oil production cost, \$/bbl | - | 8-10-12 |
| Water injection cost, \$/bbl | - | 1-2-8 |
| Water production cost, \$/bbl | - | 1-2-3 |
| Polymer cost, \$/lb | - | 1-2-3-4 |
| Incremental polymer production cost, \$/bbl | - | 0-0.5-1 |
| Incremental polymer injection cost, \$/bbl | - | 0.25-0.5-1 |

Table 5.9-Ranges used for economic parameters for the polymer flooding sensitivities

Figure 5.22 shows the relation between net present value and polymer concentration at different oil prices of \$30, \$50, \$80, \$115, and \$150/bbl with economic parameters set as follows: water flooding 3 years; IOPC \$8/bbl; WIC \$1/bbl; WPC \$1/bbl; PC \$1/lb; IPPC \$0/bbl; IPIC \$0.25/bbl.

The observations from the graphs are as follows:

- At low oil price of \$30 and \$50 and \$80, all NPV values are negative.
- At oil price of \$115 and \$150, the NPV values are positive for polymer concentration of 100, 200, and 300 ppm and then falls.
- The more years of polymer flooding, the lower the NPV (the lowest curve on each graph is for 10 years of polymer flooding except at oil price of \$30, the highest curve is for 1 year at oil prices of \$50, \$80, \$115, and \$150/bbl).

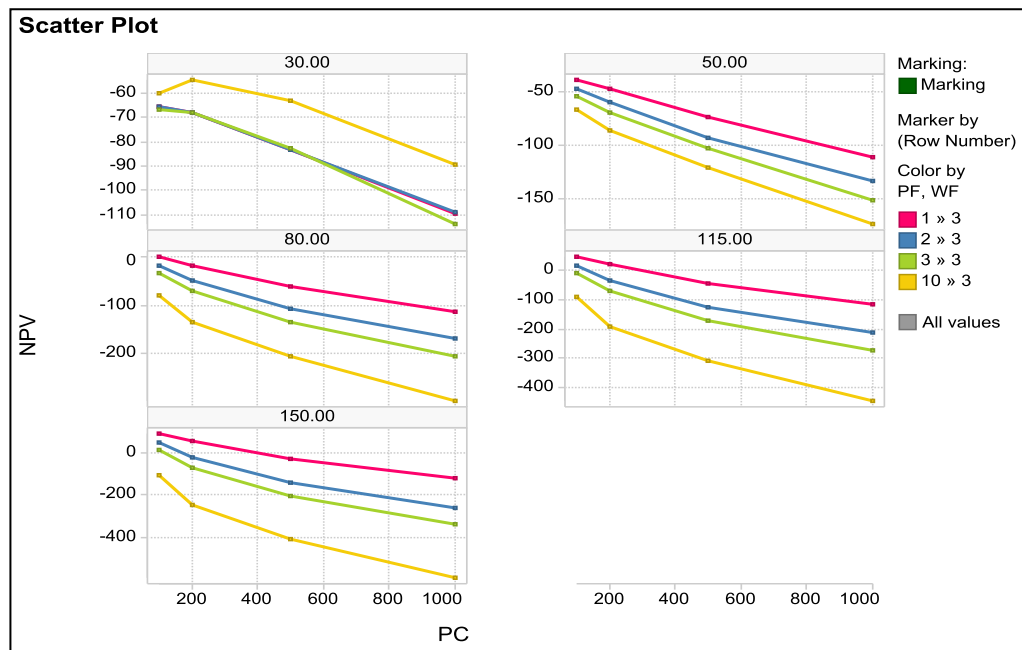


Figure 5.22 Net present value vs. polymer concentrations at different oil prices when the polymer is injected after 3 years of waterflooding; each graph is for a different oil price (\$30, \$50, \$80, \$115, \$150/bbl). On the x-axis is polymer concentration, on the y-axis is NPV. Each line is for a different number of years of polymer flooding (1, 2, 3 and 10).

Figure 5.23 shows the relation between net present value and polymer concentration at oil price of \$30/bbl and \$150/bbl with economic parameters set as follows: WF 3 years; PF 1 and 10 years; IOPC \$8/bbl; WIC \$1/bbl; WPC \$1/bbl; PC \$4/lb; IPPC \$0/bbl; IPIC \$0.25/bbl).

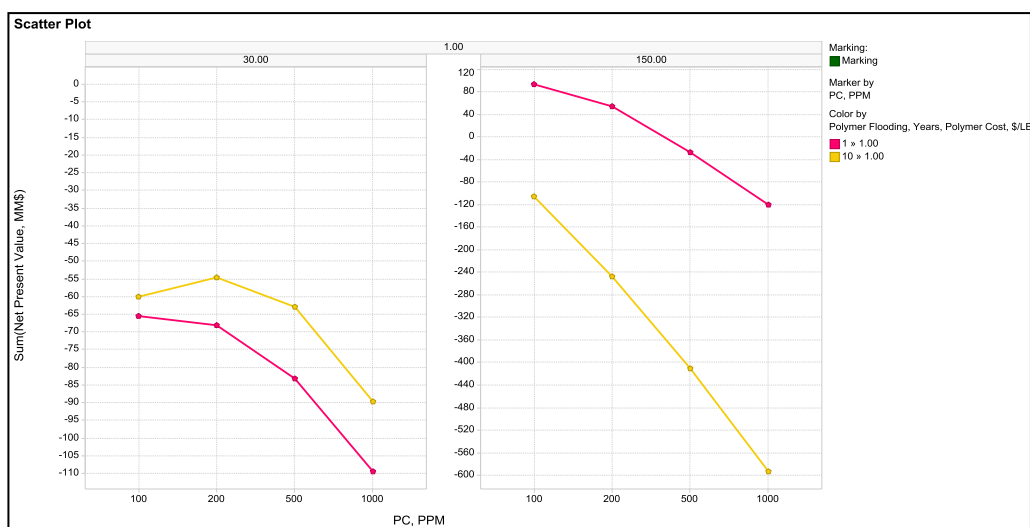


Figure 5.23 Net present value versus polymer concentrations with polymer cost (\$1 /lb) with oil prices of \$30/bbl and \$150/bbl when the polymer injected for 1 year after 3 years of waterflooding

Figure 5.24 shows the relation between net present value and polymer concentration at oil price of \$30/bbl and \$150/bbl with economic parameters set as follows: WF 3 years; PF 1 and 10 years; IOPC \$8/bbl; WIC \$1/bbl; WPC \$1/bbl; PC \$4/lb; IPPC \$0/bbl; IPIC \$0.25/bbl).

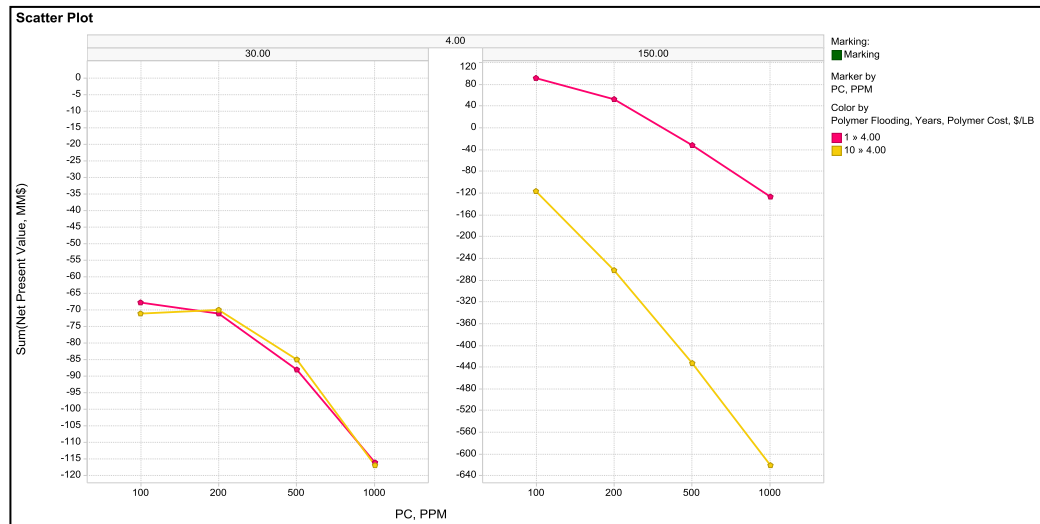


Figure 5.24 Net present value versus polymer concentrations with polymer cost (\$4 /lb) with oil prices of \$30/bbl and \$150/bbl when the polymer injected for 1year after 3 years of waterflooding

Here, we conclude that for Figure 5.23 & Figure 5.24;

- At \$30/bbl oil price the NPV are all negative when the polymer injected for 1 and 10 years with increasing polymer concentration at polymer cost of \$1 /LB. However, at \$30/bbl the relative impact of the polymer cost is more evident.
- At \$150/bbl oil price at polymer cost of \$1 /LB, the NPV is positive and decreases continuously when the polymer is injected for 1 year with polymer concentration of 100, 200, and 300 ppm.
- At \$150/bbl oil price at polymer cost of \$1 /LB, the NPV is negative with polymer concentration higher than 300 ppm.

Figure 5.25 shows the probability distribution of net present values at oil price of \$30 and different polymer concentrations of 100, 200, 500, and 1000 ppm with economic

parameters set as follows: WF 3 years; IOPC \$8/bbl; WIC \$1/bbl; WPC \$1/bbl; PC (2) \$1/lb; IPPC \$0/bbl; IPIC \$0.25/bbl. We note that the standard deviation increases with polymer concentration. The scenarios with polymer concentration of 100 ppm have less uncertainty in NPV because all the values are close to the mean, while more uncertainty on NPV occurred for polymer concentrations of 200, 500, and 1000 ppm. However at \$30/bbl and at different polymer concentrations of 100, 200 and 500 ppm, there is a very high risk of failure because all of the NPV values are negative, and also there is high risk of failure at 1000 ppm.

Bar Chart

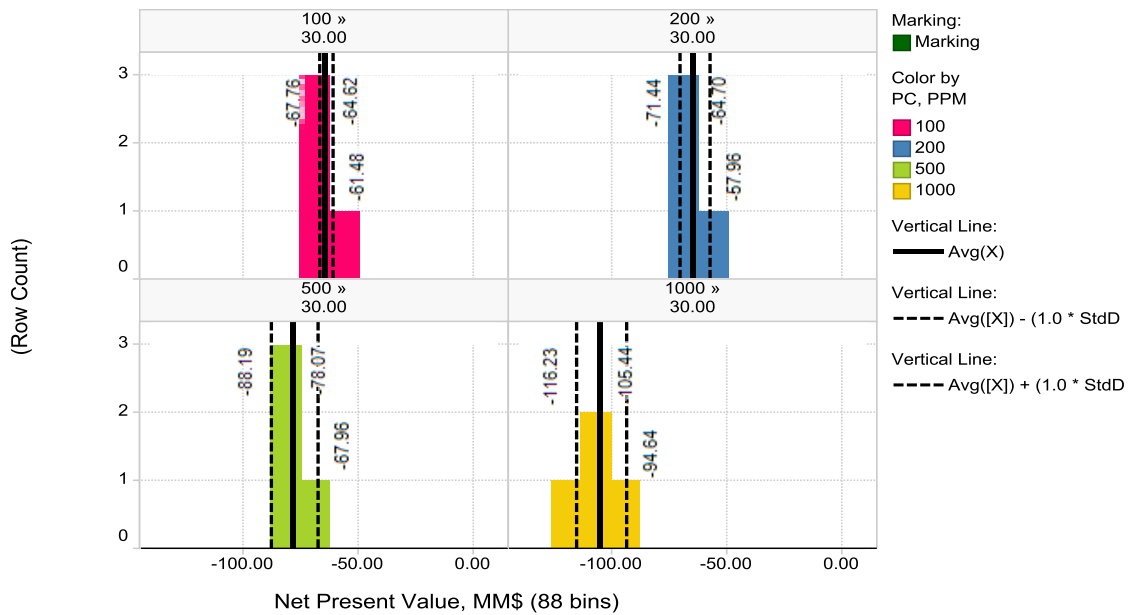


Figure 5.25 Probability distribution of net present value at different polymer concentration of 100, 200, 500, and 1000 ppm and \$30/bbl oil price

Figure 5.26 shows the probability distribution of net present values at oil price of \$150 and different polymer concentrations of 100, 200, 500, and 1000 ppm with economic parameters set as follows: WF 3 years; IOPC \$8/bbl; WIC \$1/bbl; WPC \$1/bbl; PC (2) \$1/lb; IPPC \$0/bbl; IPIC \$0.25/bbl. Polymer concentration of 100 ppm has less uncertainty in NPV because it has less varies as all the values are close to the mean, while more uncertainty in NPV occurred for polymer concentration of 200, 500, and 1000 ppm. We note again that the standard deviation increases with polymer concentration. At \$150/bbl oil price and polymer concentration of 100 ppm the relative impact on the Net Present Value is more evident. However at \$150/bbl and at different polymer concentration of 100, 200, 500 and 1000 ppm, although the uncertainty is a higher, there is higher risk of failure.

Bar Chart

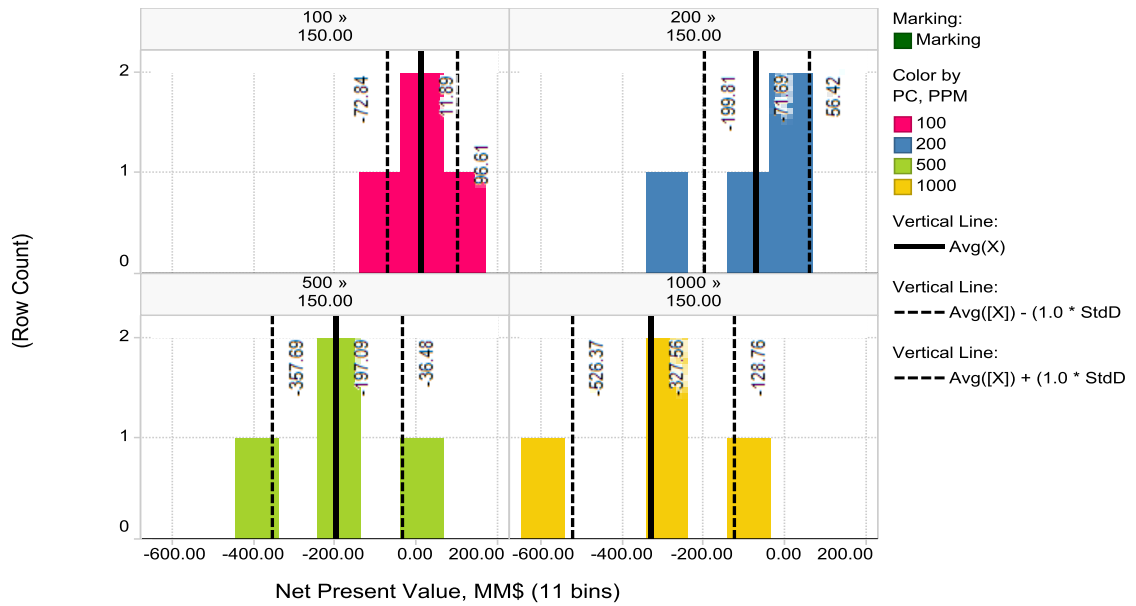


Figure 5.26 Probability distribution of net present value at different polymer concentration of 100, 200, 500, and 1000 ppm and \$30/bbl oil price

Table 5.10 shows the statistical data for polymer flooding sensitivity scenarios which are average net present value, standard deviation, and the probability of loss to each scenario, respectively. The probability of loss ($1 - \text{NormDist}(X, \text{Mean}, \text{Standard Deviation})$) in all scenarios is between 70-98 % at all oil prices. The conclusion is identified that the polymer injection would indeed be an economically unfavourable option for the Arbroath Field.

| Polymer Concentration, ppm | Statistics | Oil price \$/BBL | | | | |
|----------------------------|---------------------|------------------|--------|--------|--------|--------|
| | | 30 | 50 | 80 | 115 | 150 |
| 100 | Avg. (NPV), mm\$ | -208.5 | -195.7 | -176.6 | -154.3 | -132.0 |
| | StdDev. (NPV) | 167.4 | 163.7 | 159.8 | 158.0 | 159.35 |
| | Probability loss, % | 89 | 88 | 87 | 84 | 80 |
| 200 | Avg. (NPV), mm\$ | -163.0 | -164.1 | -165.9 | -167.9 | -170.0 |
| | Avg. (NPV), mm\$ | 157.1 | 147.7 | 137.7 | 133.2 | 137.2 |
| | Probability loss, % | 85 | 87 | 89 | 90 | 89 |
| 500 | Avg. (NPV), mm\$ | -112.0 | -131.8 | -161.6 | -196.3 | -231.0 |
| | StdDev. (NPV) | 156.0 | 141.1 | 124.5 | 117.3 | 125.3 |
| | Probability loss, % | 76 | 82 | 90 | 95 | 97 |
| 1000 | Avg. (NPV), mm\$ | -91.3 | -128.4 | -183.9 | -248.7 | -315.5 |
| | StdDev. (NPV) | 173.5 | 155.2 | 135.9 | 130.4 | 145.0 |
| | Probability loss, % | 70 | 80 | 91 | 97 | 98 |

Table 5.10-Polymer flooding average NPV, Standard deviation and the probability of loss at different oil prices

5.10 Infill well drilling compared to polymer for high viscosity oil scenario

5.10.1 Reservoir simulation 2 for infill well drilling

In this second set of calculations, an oil viscosity two orders of magnitude greater (about 50 cP) was used. From the fractional flow analysis it was clear that any small additional oil recovery in the original low viscosity case would probably offset by increase operational cost, so this high viscosity scenario was tested to see if there are any conditions in which such a system, with a heavier oil, would be appropriate for polymer flooding.

Four Infill wells were drilled and put on production (TAB, TAC, TAD, and TAF) in 1999 after eight years of water flooding. The sensitivity used in this scenario with all four new infill wells is open (Table 5.5). The same system described in section 5.7 was used in infill drilling case 1- low viscosity oil, except here the oil viscosity was increased from 0.4 cP to about 50 cP and also the same reservoir simulation procedures were used as in section 5.8.1.

Figure 5.27 shows the field oil production total. For the new infill well drilling (TAB, TAC, TAD, and TAF) compared to waterflooding scenario.

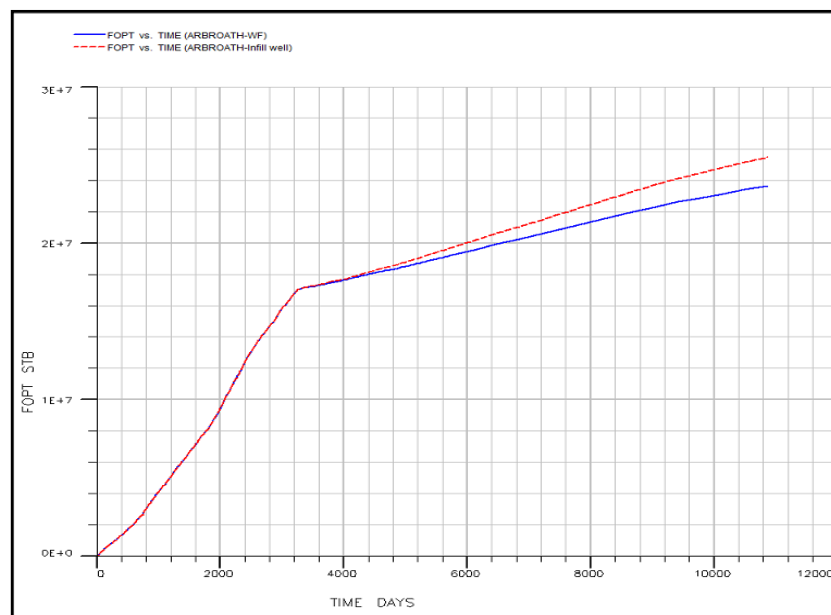


Figure 5.27 Field oil production total between water flooding & infill well drilling

Figure 5.28 shows the field water injection total of the new infill well drilling (TAB, TAC, TAD, and TAF) compared to waterflooding scenario. The cumulative water injection is almost identical in both cases because the water injection controls remain unchanged.

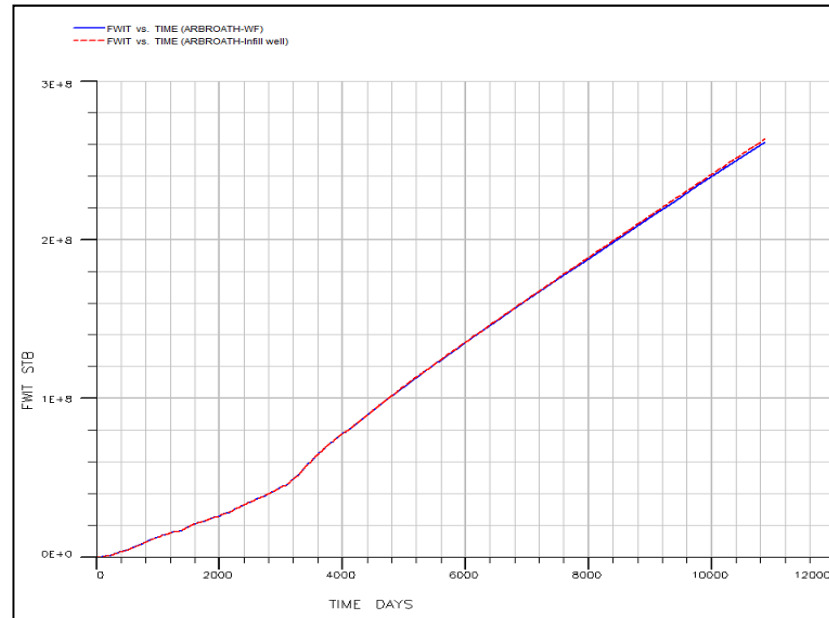


Figure 5.28 Field water injection total between water flooding & infill well drilling

Figure 5.29 shows the field water production total of the new infill well drilling (TAB, TAC, TAD, and TAF) compared to waterflooding scenario.

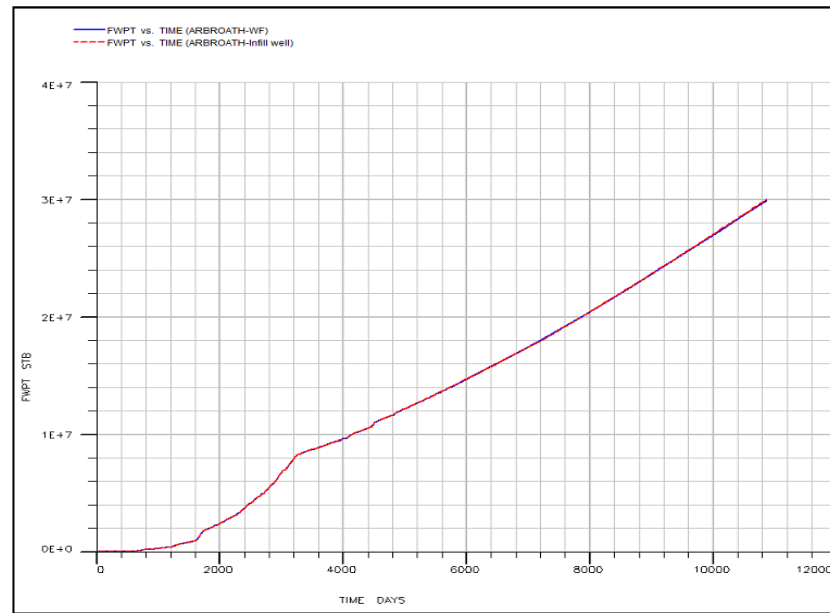


Figure 5.29 Field water Production total between water flooding & infill well drilling

The four new wells are located in zones that have not been swept by water, and thus the water cut in these wells remains very low. For this reason there is very little change in the field water production when these new wells are drilled, and for the duration of this calculation (around 30years)

5.10.2 Economic model 1 for infill well drilling

The same input and output methodology was applied as in section 5.8.2 and then the same procedure to sensitivity and risk analysis for infill well drilling as in section 5.8.3 was used. The variable range that used is described in Table 5.4.

The relation between Net Present Value (NPV) versus different oil prices of \$30 /bbl, \$50 /bbl, \$80 /bbl, \$115 /bbl, and \$150 /bbl respectively, for infill wells drilling are illustrated in Figure 5.30, with discount rate of 10%, incremental oil price cost \$8 /bbl, water injection cost \$1 /bbl, water production cost \$1 /bbl, well operating cost 1mm\$, and well capital cost 10mm\$. As can be seen the highest Net Present Value (NPV) occurred where at \$150/bbl. The values of the Net Present Value (NPV) for all scenarios are summarised below in Table 5.11.

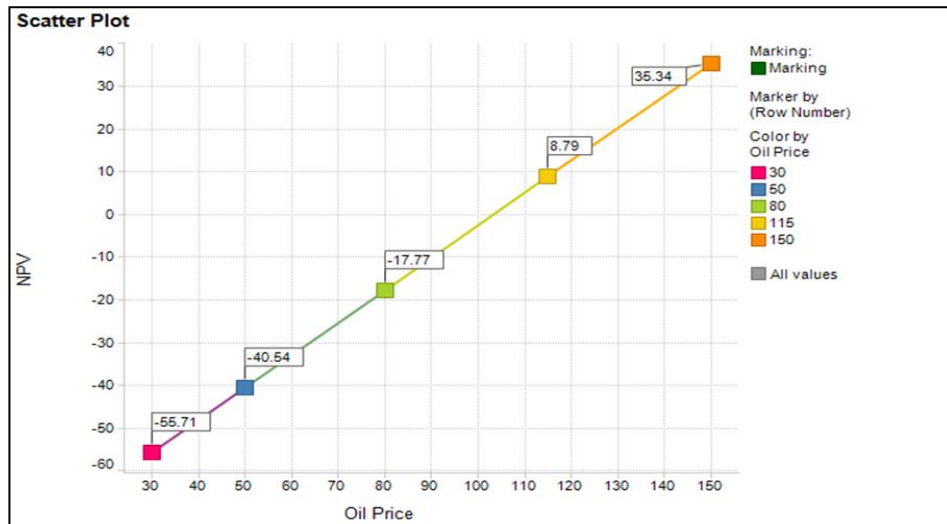


Figure 5.30 Net present value (NPV) versus of different oil prices of \$30 /bbl, \$50 /bbl, \$80 /bbl, \$115 /bbl, and \$150 /bbl of different sensitivities of infill wells drilling

Note that infill well drilling only has a positive NPV for oil prices above \$115/bbl. This scenario represents the case where all wells are open. Other scenarios (some wells shut) give lower NPV.

| Infill wells | Statistics | Oil price \$/BBL | | | | |
|--------------|---------------------|------------------|-----|-----|-----|-----|
| | | 30 | 50 | 80 | 115 | 150 |
| All Open | Avg. (NPV), mm\$ | -111 | -95 | -73 | -46 | -20 |
| | StdDev. (NPV) | 31 | 31 | 31 | 31 | 31 |
| | Probability loss, % | 100 | 100 | 99 | 93 | 74 |

Table 5.11 - Infill well drilling average NPV, Standard deviation and the probability of loss at different oil prices

This analysis suggests that at low oil prices infill well drilling will not be viable, but even at high oil prices there will be a high probability of loss.

5.10.3 Reservoir simulation 2 for polymer flood

The procedure of the input and the output for the reservoir simulation 2 calculations were the same as in section 5.9.1.

16 sensitivities have been run with polymer concentrations: 100, 200, 500, and 1000 ppm.

Figure 5.31 & Figure 5.32 show that the field oil production total during the polymer flood scenarios rises higher than during the conventional water flooding when the polymer concentration of 100 and 200 ppm for 1, 2, 3 and 10 years of polymer flood is used, and higher than the infill well scenario for 3 and 10 years of polymer flooding, and then the model stopped running because the water cut exceeded the 98 % limit.

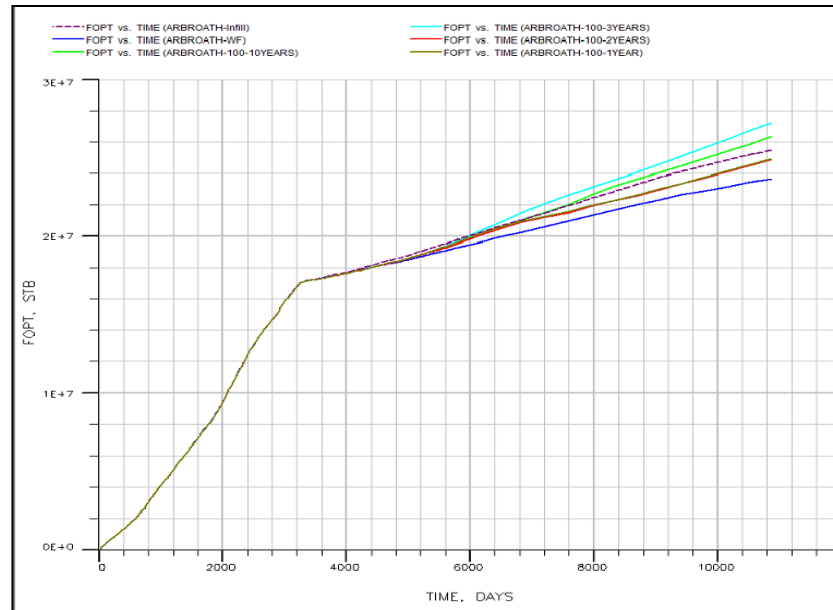


Figure 5.31 Field oil production total for polymer concentration of 100 ppm compared to water flooding and infill well

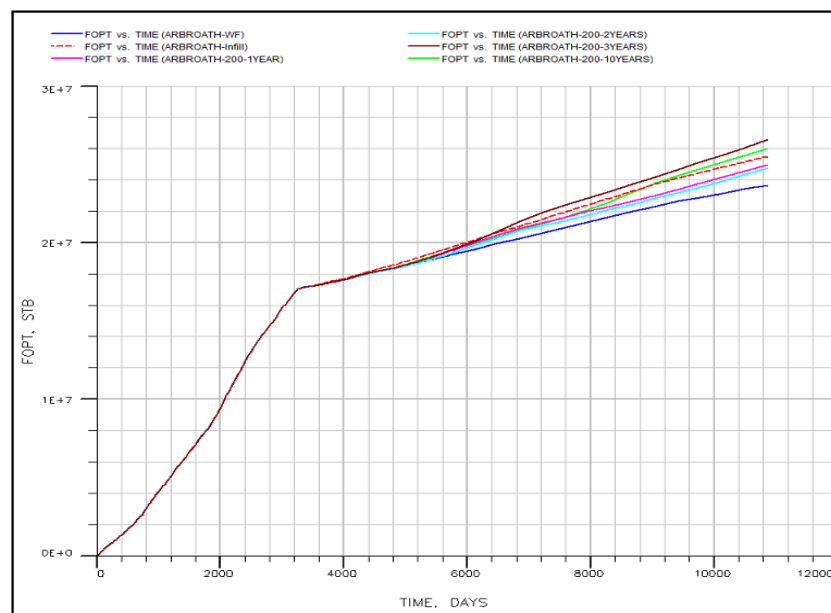


Figure 5.32 Field oil production total for polymer concentration of 200 ppm compared to water flooding and infill well

Figure 5.20 and Figure 5.34 show that the field oil production total during the polymer flood scenarios continues to rise higher than during the conventional water flooding when the polymer concentration of 500 and 1000 ppm for 1, 2, and 3 years of polymer flood is used, and higher than the infill well scenario for 3 years of polymer flooding, and then the model stopped running because the water cut exceeded the 98 % limit.

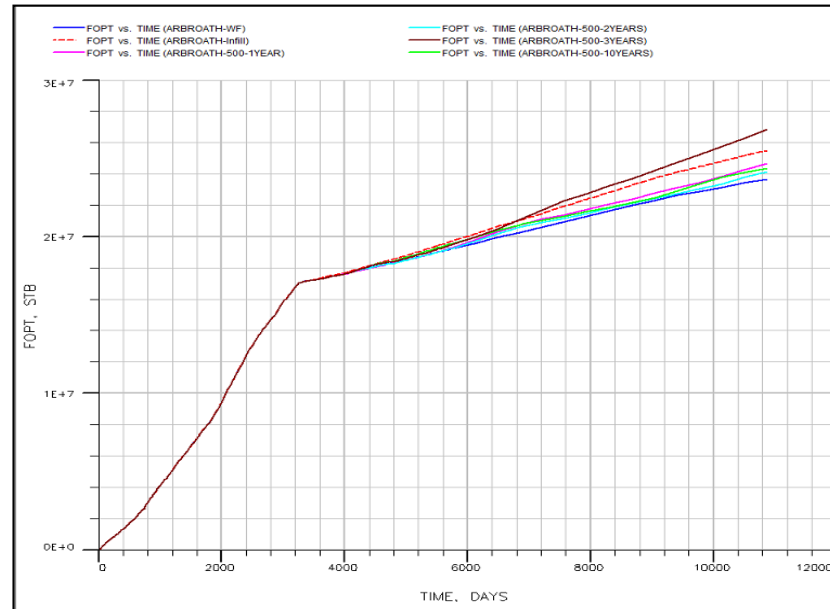


Figure 5.33 Field oil production total for polymer concentration of 500 ppm compared to water flooding and infill well

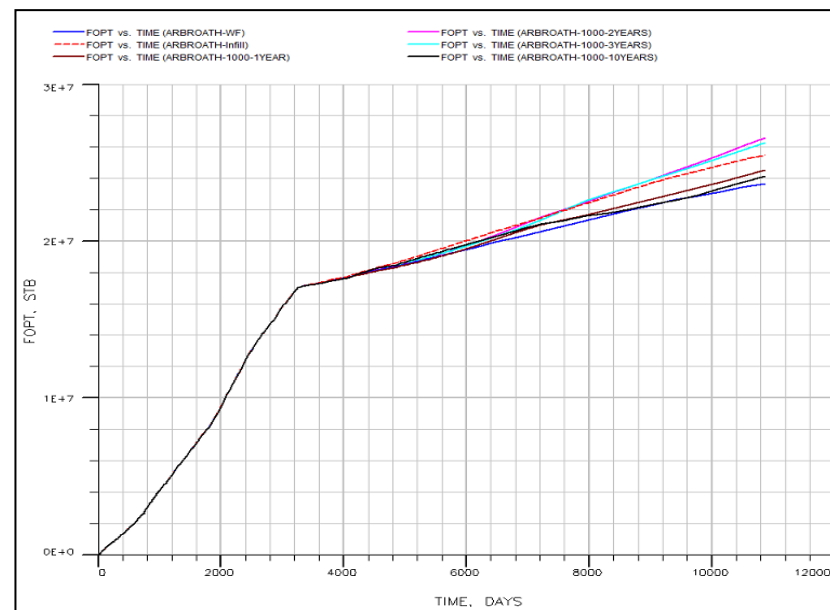


Figure 5.34 Field oil production total for polymer concentration of 1000 ppm compared to water flooding and infill well

It appears that there is an optimal polymer flooding period of 3 years for all polymer concentrations, except at highest polymer concentration of 1000 ppm, where 2 years of polymer injection gives the highest recovery. For 1000 ppm polymer concentration, injection for 1 year or 10 years gives a lower recovery than infill well drilling.

Figure 5.35 to Figure 5.38 shows the field water injection total of polymer concentration of 100, 200, 500 and 1000 ppm at 1, 2, 3 and 10 years of polymer flood compared to waterflooding and infill well drilling scenarios.

It is clear that the more polymer that is injected, the less water that is injected. This is not because polymer is replacing water, but because injectivity reduces due to the greater resistance of polymer to flow once it is in the reservoir. This is important, because as already noted; voidage replacement must be maintained to avoid pressure dropping below the bubble point. If this occurs, productivity may decline due to reduced oil mobility under three phase flow. Thus, to gain the benefit of reduced brine mobility with polymer injection, it may be necessary to consider upgrading of the injector facilities (pumps, perhaps additional wells) to maintain overall injectivity.

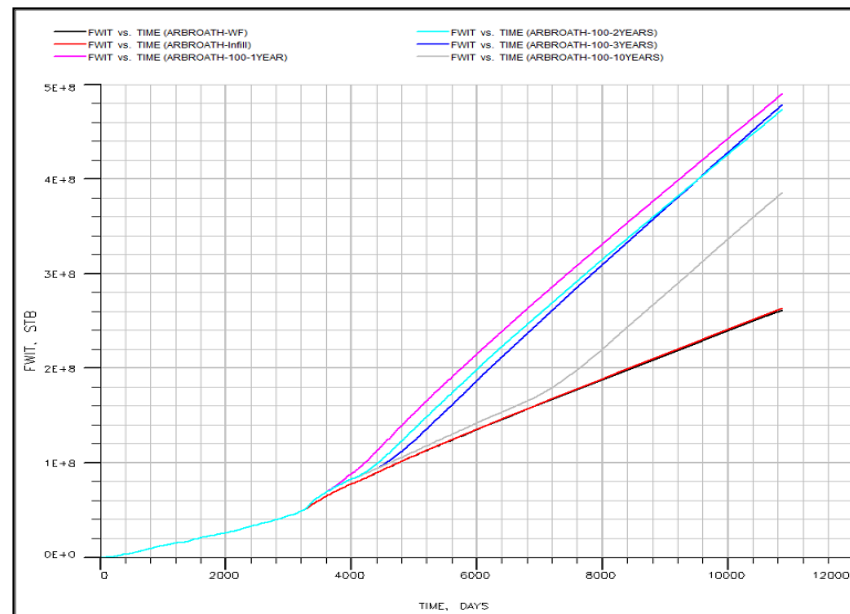


Figure 5.35 Field water injection total between polymer flooding of 100 ppm, water flooding & infill well drilling

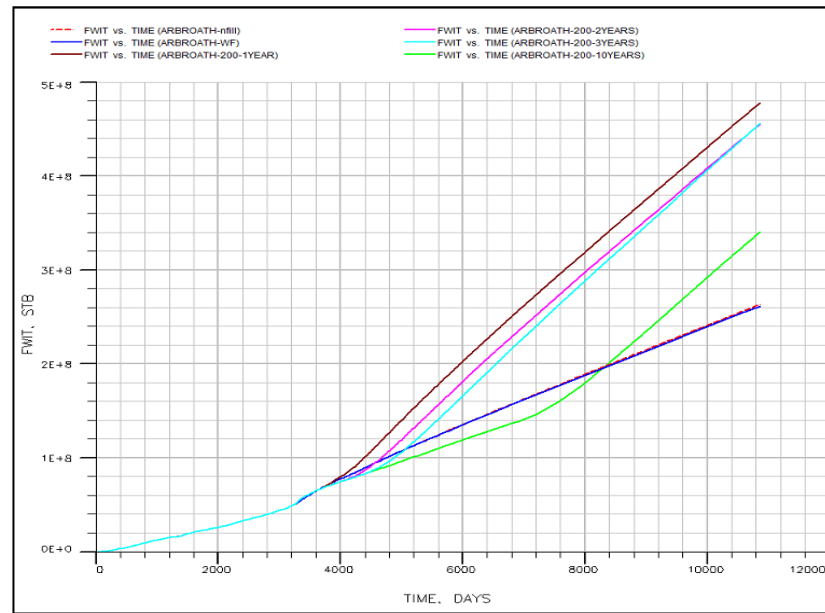


Figure 5.36 Field water injection total between polymer flooding of 200 ppm, water flooding & infill well drilling

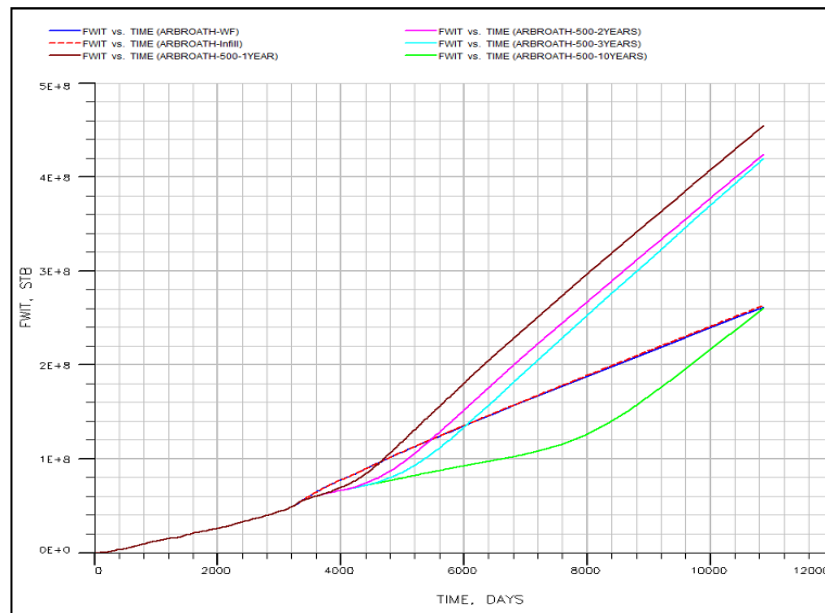


Figure 5.37 Field water injection total between polymer flooding of 500 ppm, water flooding & infill well drilling

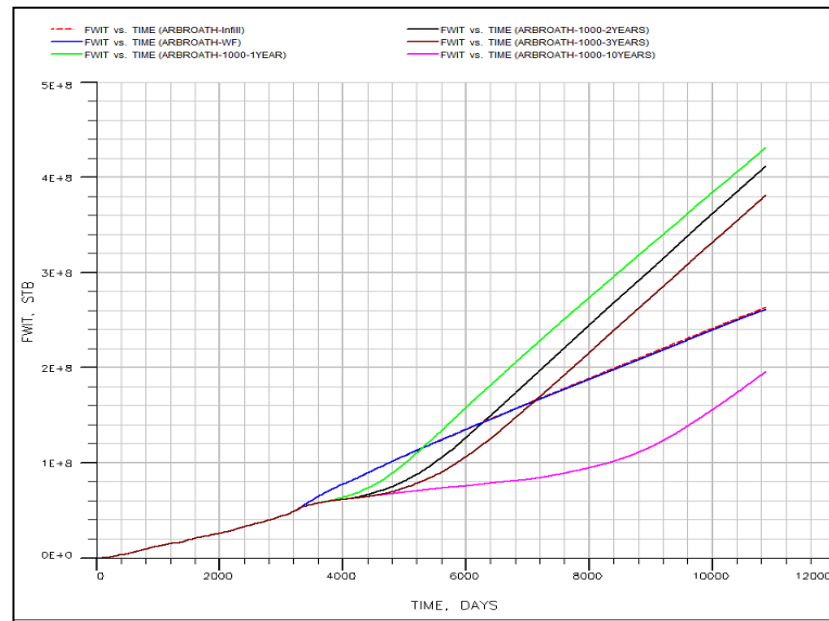


Figure 5.38 Field water injection total between polymer flooding of 1000 ppm, water flooding & infill well drilling

Figure 5.39 & Figure 5.42 shows that the field water production total during the polymer flood scenarios is higher than the water flooding and infill well drilling cases when the polymer concentration of 100, 200 and 500 ppm is used for 1, 3, 5, and 10 years of polymer flooding, and is lower when the polymer concentration 1000 ppm is used for 10 years only of polymer flooding. This is because greater injection capacity was required to maintain reservoir pressure when polymer is used (See Figures 5.33-5.36)

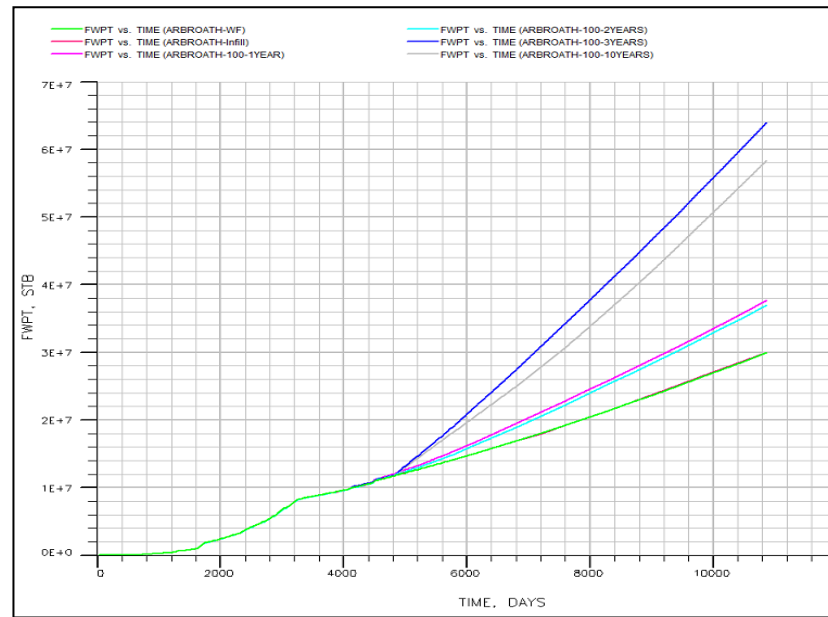


Figure 5.39 Field water production total between polymer flooding of 200 ppm, water flooding & infill well drilling

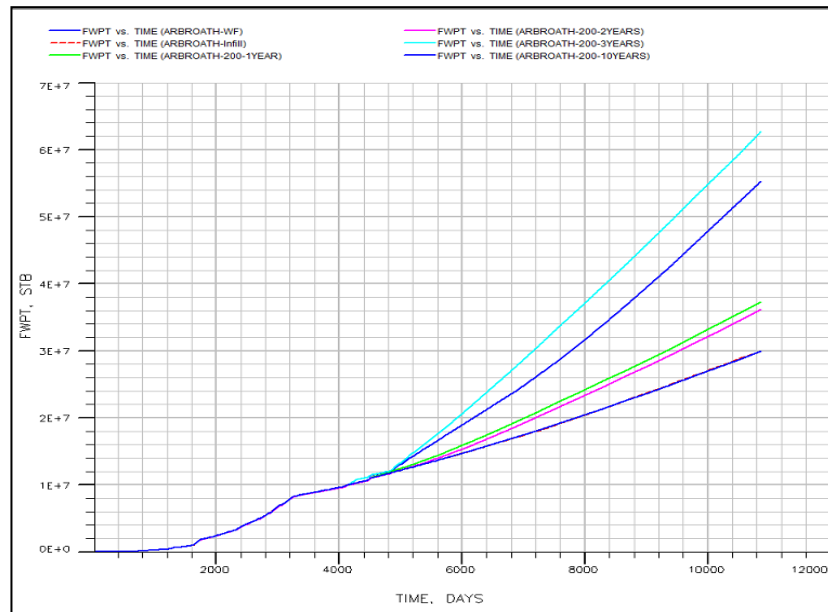


Figure 5.40 Field water production total between polymer flooding of 200 ppm, water flooding & infill well drilling

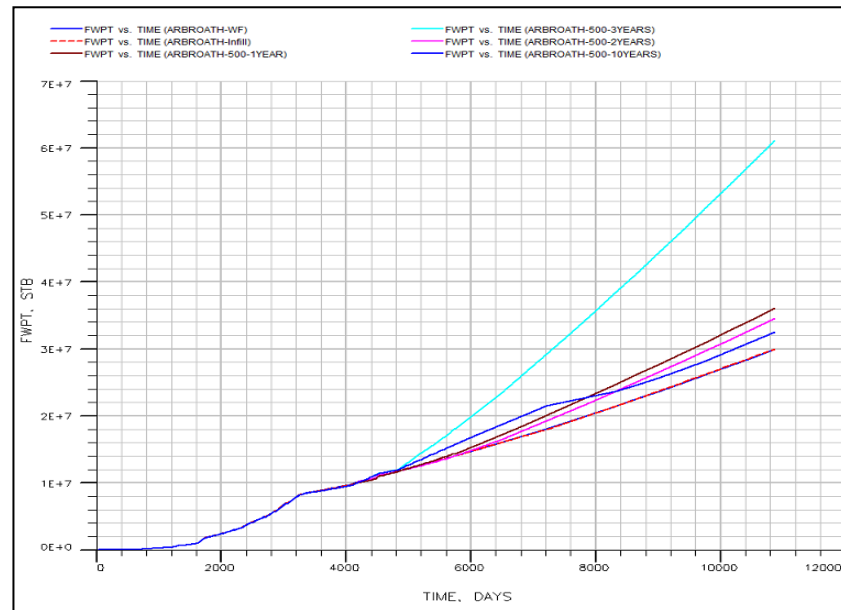


Figure 5.41 Field water production total between polymer flooding of 500 ppm, water flooding & infill well drilling

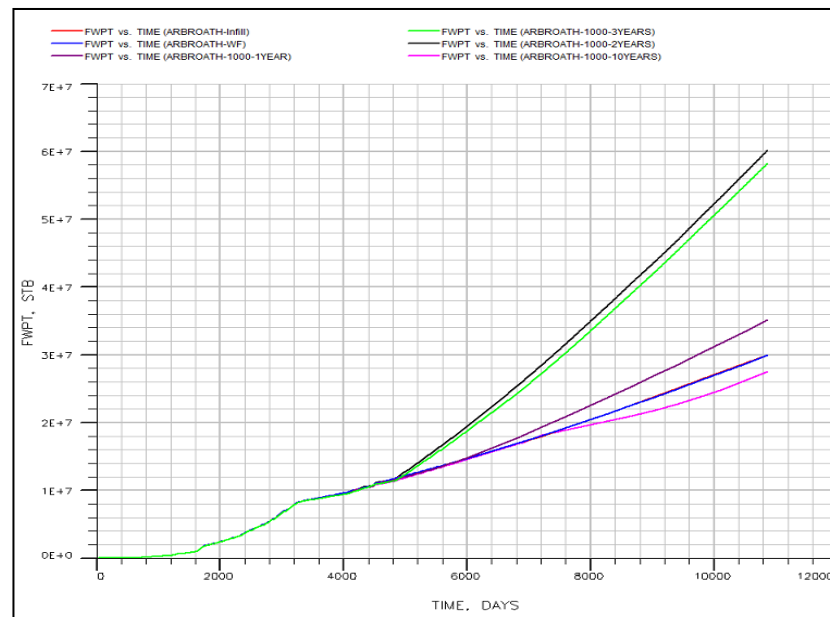


Figure 5.42 Field water production total between polymer flooding of 1000 ppm, water flooding & infill well drilling

5.10.4 Economic model 2 for infill well drilling

The same input and output methodology was applied as in section 5.9.2 and then the same procedure to sensitivity and risk analysis for polymer flooding as in section 5.9.3 was used. The ranges of the variables that are used to assess the design, using project profitability measures as the decision making tool in the economic model of the polymer flooding scenarios, are given in Table 5.9.

Figure 5.43 to Figure 5.45 shows the relation between net present value and polymer concentration at different oil prices of \$30, \$50, \$80, \$115, and \$150/bbl with economic parameters set as follows: water flooding 3 years; IOPC \$8/bbl; WIC \$1/bbl; WPC \$1/bbl; PC \$1/lb; IPPC \$0/bbl; IPIC \$0.25/bbl.

The observations from the graphs are as follows:

- At low oil price of \$30 and \$50 and \$80, all NPV values are negative.
- At oil price of \$115, NPV values are negative when the polymer injected for 1 and 2 years respectively.
- At oil price of \$150, the NPV values are positive for all polymer concentration.
- The highest NPV occurs for 3 years of polymer flood at oil prices of 150/bbl.
- At oil prices of 150/bbl, NPV is negative at 1 and 2 years of polymer flood at 500 ppm polymer concentration and then positive at polymer concentration of 1000 ppm.

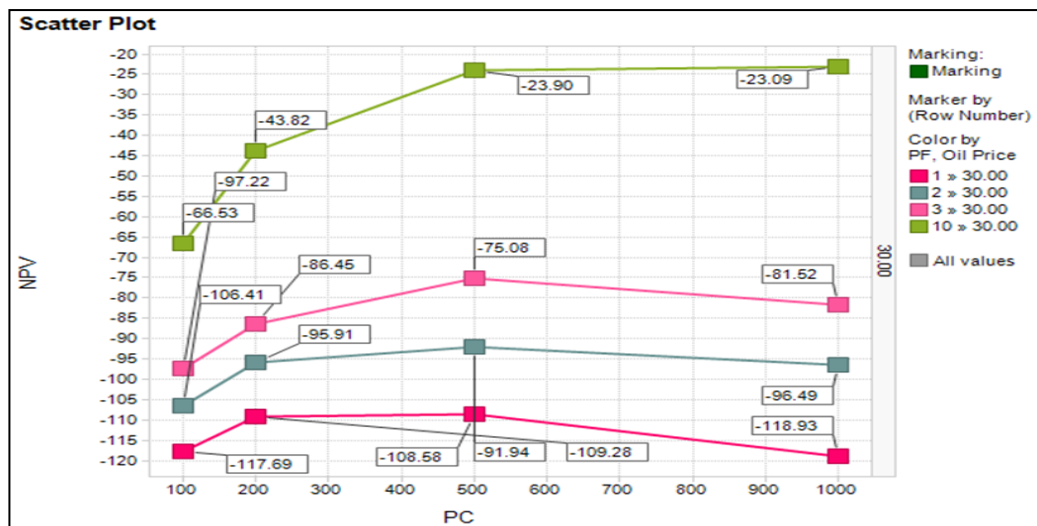


Figure 5.43 Net present value vs. polymer concentrations at different oil prices; each graph is for a different oil price (\$30/bbl). On the x-axis is polymer concentration, on the y-axis is NPV. Each line is for a different number of years of polymer flooding (1, 2, 3 and 10).

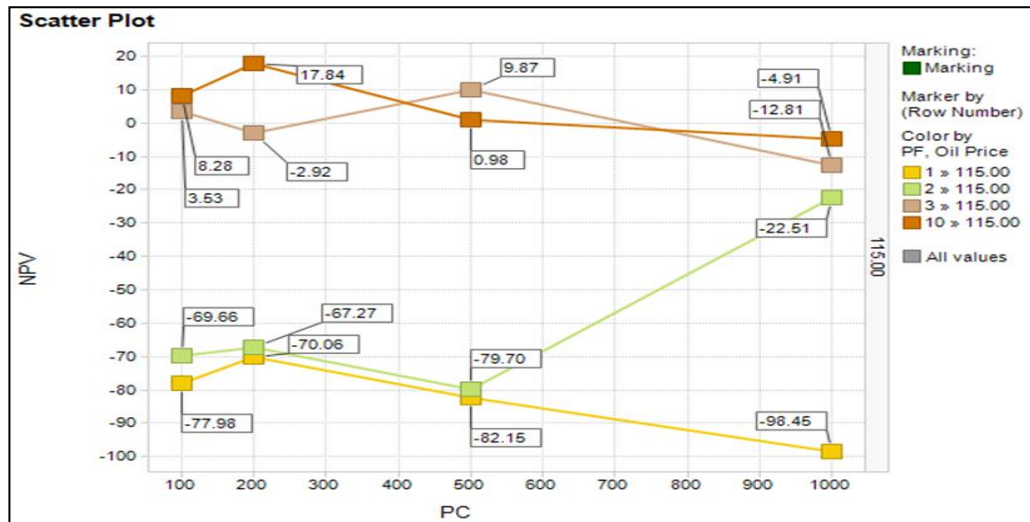


Figure 5.44 Net present value vs. polymer concentrations at different oil prices; each graph is for a different oil price (\$115/bbl). On the x-axis is polymer concentration, on the y-axis is NPV. Each line is for a different number of years of polymer flooding (1, 2, 3 and 10).

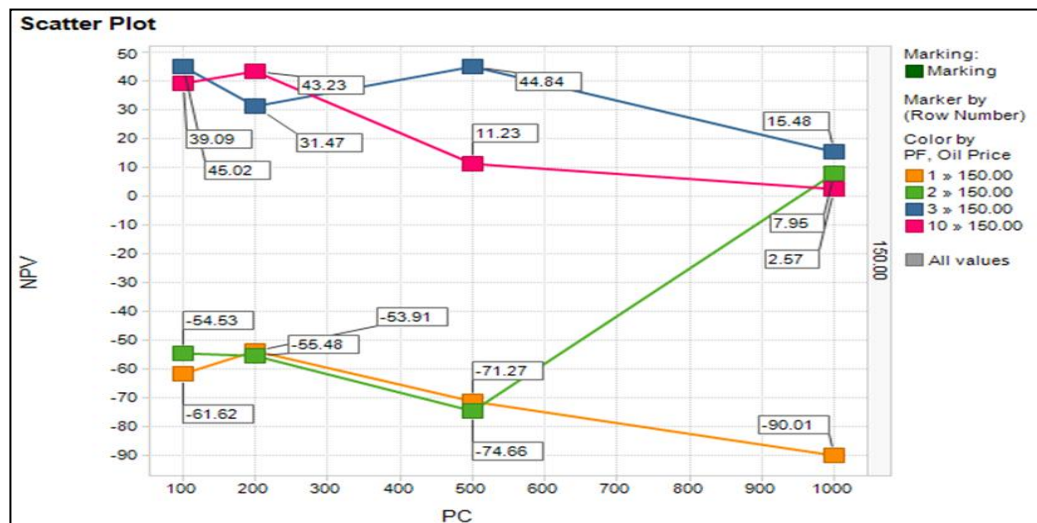


Figure 5.45 Net present value vs. polymer concentrations at different oil prices; each graph is for a different oil price (\$150/bbl). On the x-axis is polymer concentration, on the y-axis is NPV. Each line is for a different number of years of polymer flooding (1, 2, 3 and 10).

Table 5.12 shows the statistical data for polymer flooding sensitivity scenarios which are average net present value, standard deviation, and the probability of loss to each scenario, respectively. The probability of loss ($1 - \text{NormDist}(X, \text{Mean}, \text{Stranded Deviation})$) in all scenarios is between 65-90 % at all oil prices. The conclusion is

identified that the polymer injection has a high risk of failure for the Arbroath Field, even the high oil viscosity case.

| Polymer Concentration, ppm | Statistics | Oil price \$/BBL | | | | |
|----------------------------|----------------------------|------------------|-----------|-----------|-----------|-----------|
| | | 30 | 50 | 80 | 115 | 150 |
| 100 | Avg. (NPV), mm\$ | -330 | -315 | -293 | -267 | -241 |
| | StdDev. (NPV) | 254 | 254 | 256 | 258 | 260 |
| | Probability loss, % | 90 | 89 | 87 | 85 | 82 |
| 200 | Avg. (NPV), mm\$ | -267 | -255 | -236 | -214 | -192 |
| | Avg. (NPV), mm\$ | 221 | 222 | 223 | 225 | 227 |
| | Probability loss, % | 89 | 87 | 86 | 83 | 80 |
| 500 | Avg. (NPV), mm\$ | -183 | -174 | -161 | -146 | -131 |
| | StdDev. (NPV) | 192 | 191 | 191 | 192 | 193 |
| | Probability loss, % | 83 | 82 | 80 | 78 | 75 |
| 1000 | Avg. (NPV), mm\$ | -136 | -125 | -109 | -90 | -72 |
| | StdDev. (NPV) | 187 | 186 | 184 | 182 | 180 |
| | Probability loss, % | 77 | 75 | 72 | 69 | 65 |

Table 5.12-Polymer flooding average NPV, Standard deviation and the probability of loss at different oil prices

5.11 Discussion

In summary, with oil viscosity of 0.4 cP all these conclusions confirm that the correct decision was made for the Arbroath Field – that the decision to drill infill wells (rather than undertake a polymer injection project) was indeed the optimum choice from an economic perspective. This is true for the economic conditions that were prevalent at the time, but also for a wide range of economic circumstances, as identified by the sensitivity calculations.

With oil viscosity of 50 cP these conclusions confirm that oil production is higher for some of the polymer flooding cases than with infill well drilling. The highest NPV (44.8 MM\$) for polymer flooding at \$150/bbl oil price compared to NPV (35.4 MM\$) for infill well drilling at the same oil price. However, there is a high probability of loss for both techniques and this is liable to be the case unless the oil price rises considerably, perhaps to over 200-300 \$/bbl.

A detailed study would consider many possible locations for infill well engineers would consider geological model, any 4D seismic data that is available and reservoir simulation calculation of bypassed oil. The location chosen in this study were those identified by field engineers, other locations could be selected to consider accelerated oil recovery.

Using this analysis here some of these scenarios may be even better than the location chosen by the reservoir engineers because full economic analysis would be applied to each scenario.

CHAPTER 6: SCIEHALLION FIELD

This study has focused on the development of a method to test the economic viability of Enhanced Oil Recovery (EOR) versus infill well drilling where the challenge is to compare polymer flooding scenarios with infill well drilling scenarios, not just based on incremental recovery, but on Net Present Value (NPV) and possible other economic indicators as well.

In the previous chapter the method was applied to the Arbroath field, where the operator has already chosen infill well drilling instead of enhanced oil recovery, to test the strength of the method against a conventional decision making process for which there is historical data.

Chapter 6 describes application of the approach to the Schiehallion field where the choice has yet to be made, a field which is currently under waterflood management, and where the operator is considering polymer flooding as an alternative (or in addition) to infill well drilling. Application of the method has identified that under certain technical conditions (related to polymer concentration and duration of polymer injection) and certain economic conditions (related to oil price and well costs) polymer flooding entails a significant risk of failure, but that if appropriate technical choices are made, and under prevailing economic conditions, polymer flooding is very beneficial for this field, and a combination of polymer flooding and infill well drilling is optimal.

6.1 Schiehallion Oil Field Overview

The Schiehallion field was discovered in 1993, lies in water depths up to 500 m and is situated on the United Kingdom Continental Shelf some 200km west of the Shetland Islands (Figure 6.1). The reservoir is a deep water turbidite (Figure 6.2), and shows varying degrees of channelization in different parts of the field Govan et al. (2005).

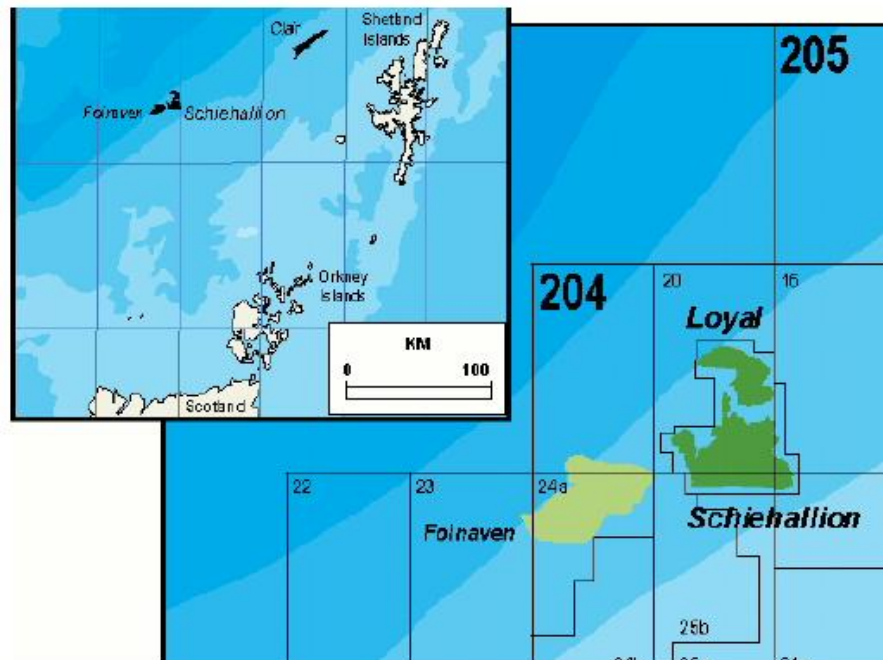


Figure 6.1 - Location of the Schiehallion field Govan *et al.* (2005)

The reservoir was discovered in 1993 by well 204/20-1 and has been appraised with five wells. Development of the field was sanctioned in 1996, development drilling began later that year, and first oil was in 1998. Oil in place is approximately 2 billion barrels. Oil is trapped in submarine slope reservoir sands of Palaeocene age. The discovery well identified an oil-water contact at 2064m TVDSS.

The field was mapped using 3D seismic data during the first half of 1994, followed by drilling of five further vertical appraisal wells in 1994-95. Three wells were operated by BP/Britoil and the other two by Amerada Hess Ltd. Production is from the relatively thin Palaeocene turbidite channel sands 10-50 m thick at a depth of about 2 km *Chapin et al.* (2000); *Parr et al.*(2000).

These wells confirmed that the reservoir quality was good, with porosity of 28 % and average horizontal permeabilities in the range of 500 to 1500 mD.

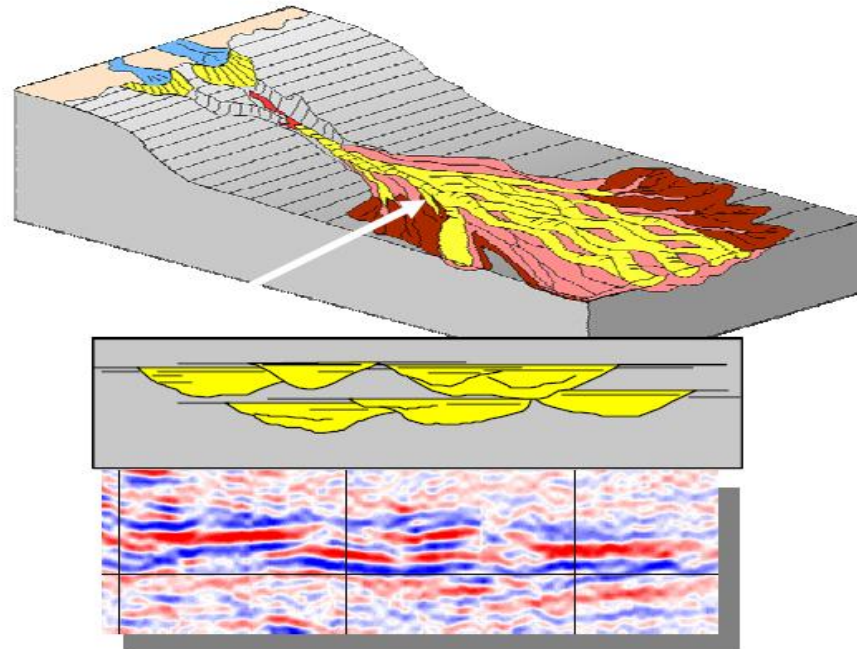


Figure 6.2 - Geological model of the Schiehallion field Govan et al. (2005)

The Schiehallion reservoir fluid is single phase black oil with gravity in the range of 22 to 28° API. Initial reservoir pressure was 2907 psia at a datum depth of 1940m TVDss. Typical values for saturation pressure and solution gas oil ratio (GOR) are 2667 psia and 342 scf/bbl, respectively, and high wax content results in a range of in-situ reservoir viscosities from 1.5 to 4.5 cP Richardson et al. (1997). A limited aquifer provides little natural energy so water injection is critical Govan et al. (2005).

The producing wells are placed horizontally in the 10-50m thick sand bodies to ensure that 300-1000m of net rock is contacted so that the wells produce at sufficiently high rates (Figure 6.3). As noted above, the initial reservoir pressure is close to bubble point, and so maintaining voidage replacement is important. The producing and injecting wells are drilled from subsea drill centres. First oil was brought through flow-lines from these drill centres into the purpose built Schiehallion F.P.S.O. (Floating Production Storage and Offloading) (Figure 6.4) vessel in late July 1998 Abigail et al. (2001).

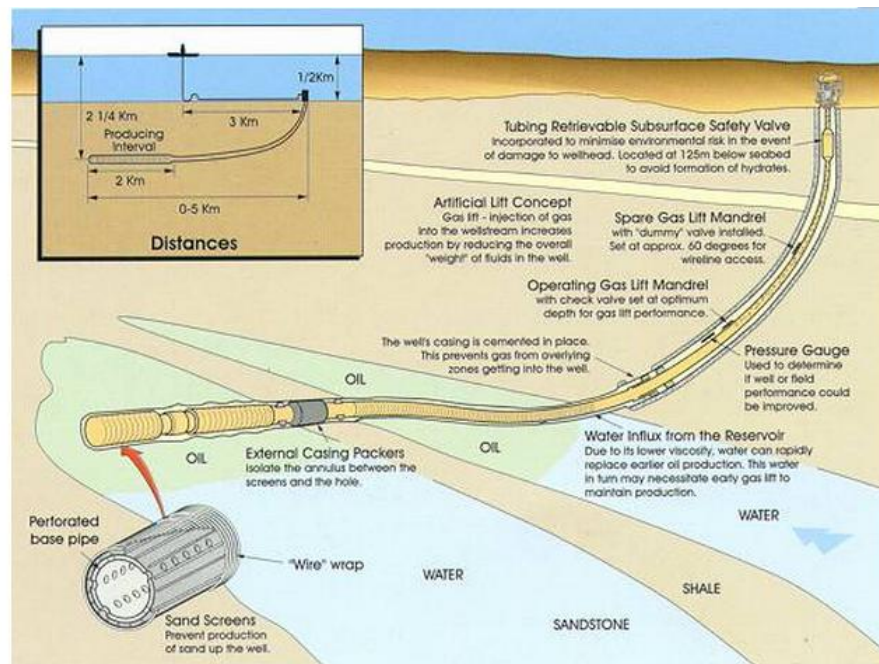


Figure 6.3 - Schematic of the reservoir formation, with a horizontal producing well of the Schiehallion field (Schiehallion Oil Field, United Kingdom)

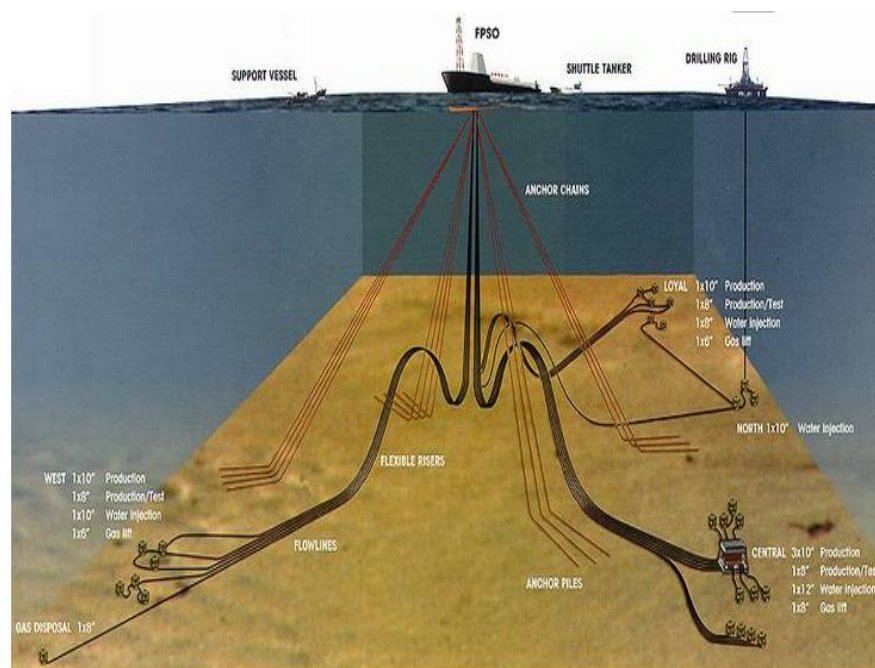


Figure 6.4 - Subsea layout, showing how the centres are connected to the FPSO of the Schiehallion field (Schiehallion Oil Field, United Kingdom)

6.2 System description

A full field model for Schiehallion was developed in 1998 by BP. The number of cells in the X direction is 193; the number of cells in the Y direction is 99, and the number of cells in the Z direction is 84. The total number of cells is 1,604,988 (Table 6.1).

| | |
|-----------------------|----------------|
| Datum Depth, ft | 6435 (1940 m) |
| Pressure, Psi | 2907 (200 bar) |
| Oil water contact, ft | 7221 (2201 m) |

Table 6.1 - Schiehallion Field data

Fractional flow and Buckley-Leverett analysis was also carried out for the Schiehallion field. Figure 6.5 shows the normalised relative permeability curves used for this field, and Figure 6.6 the fractional flow curves with and without addition of polymer.

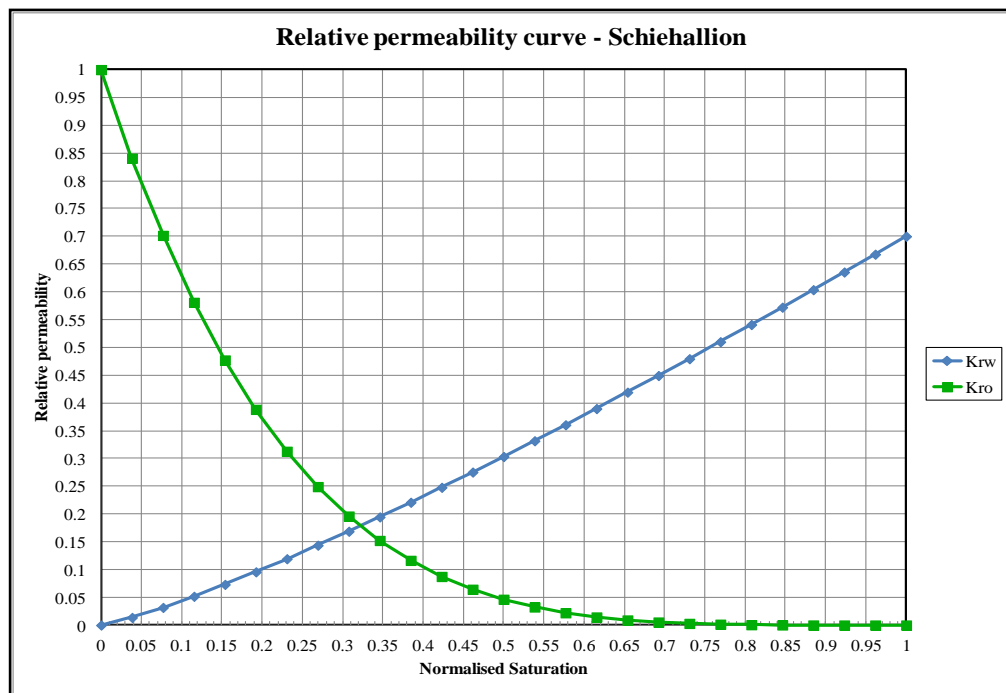


Figure 6.5 - Typical normalised relative permeability curve for Schiehallion Field

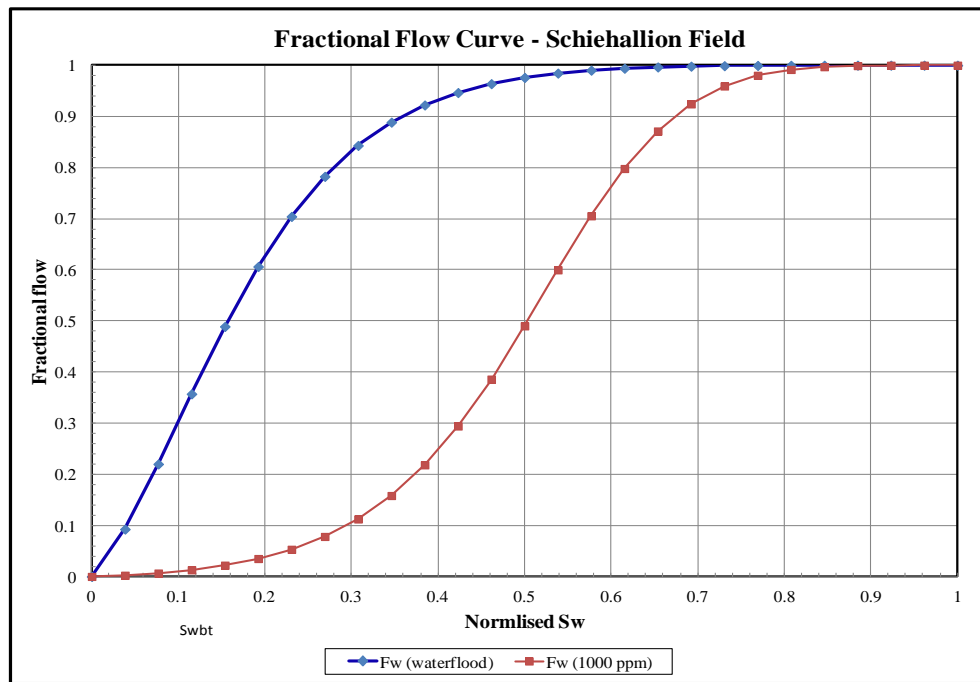


Figure 6.6 - Typical fractional flow curve for the Schiehallion Field for original waterflooding conditions and assuming 1000 ppm polymer concentration.

The fractional flow theory that was used in chapter 3 was applied to generate the following result, as shown in Table 6.2 and Table 6.3.

| case | S_{wbt} | Reservoir | Surface | $\overline{\overline{S_{wbt}}}$ | $N_{pdpt} (PV)$ |
|----------|-----------|-----------|------------|---------------------------------|-----------------|
| | | f_{wbt} | f_{wsbt} | | |
| WF | 0.15 | 0.49 | 1.76 | 0.31 | 0.27 |
| 1000 ppm | 0.63 | 0.83 | 1.04 | 0.76 | 0.72 |

Table 6.2 - Oil recoveries and saturation at breakthrough for Buckley-Leverett method

| case | μ_o/μ_w | S_{wf} | $K_{rw}(S_{wf})$ | $K_{ro}(S_{wf})$ | M_s | M |
|----------|---------------|----------|------------------|------------------|-------|-------|
| WF | 6.24 | 0.15 | 0.07 | 0.47 | 0.91 | 4.2 |
| 1000 ppm | 0.15 | 0.63 | 0.43 | 0.007 | 0.06 | 0.098 |

Table 6.3 - Values of the shock front and end point relative permeabilities calculated using fractional flow.

In the case of the Schiehallion Field there is clearly a significant increase in the hydrocarbon pore volume recovered by breakthrough time when polymer is added, increasing this value from 0.27 for the waterflood to 0.72 for the scenario where polymer is used. The pore volumes injected at breakthrough are therefore increased from 0.28 PVI for the waterflood to 0.88 PVI for the polymer flooding scenario. This is reflected in the saturation profiles shown in Figure 6.7.

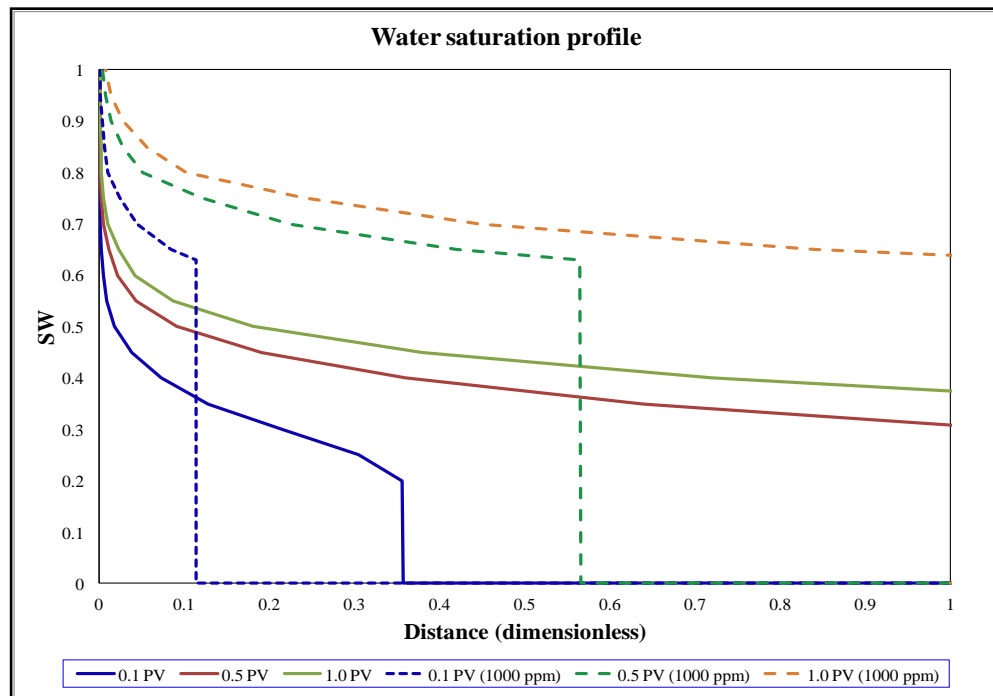


Figure 6.7 - Water saturation profile as a function of distance and time

6.3 Water flooding

Figure 6.8 illustrates stage one of water flooding for Schiehallion field development with fifteen production and injector wells.

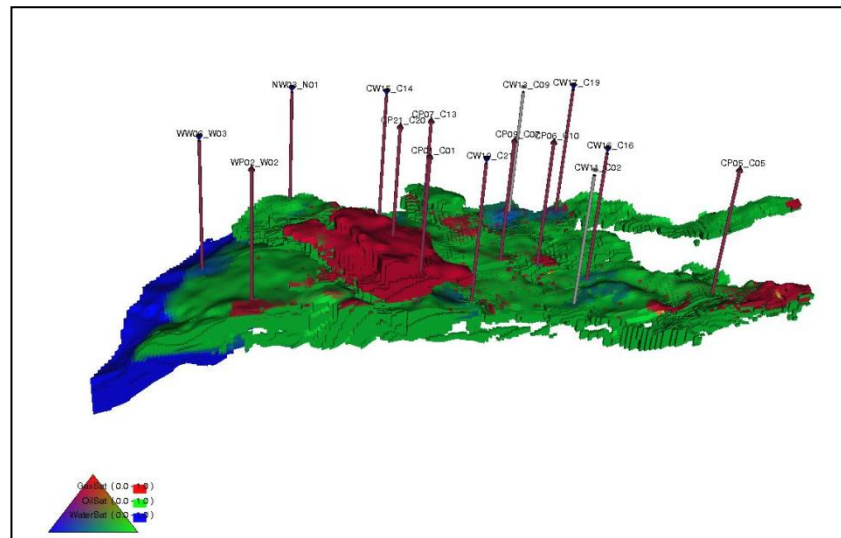


Figure 6.8 - Schiehallion field model (stage one - waterflooding)

6.4 Infill well drilling

Figure 6.9 illustrates stage two of infill well drilling for the Schiehallion field development. Five producer and injectors were drilled, making the total twenty production and injection wells.

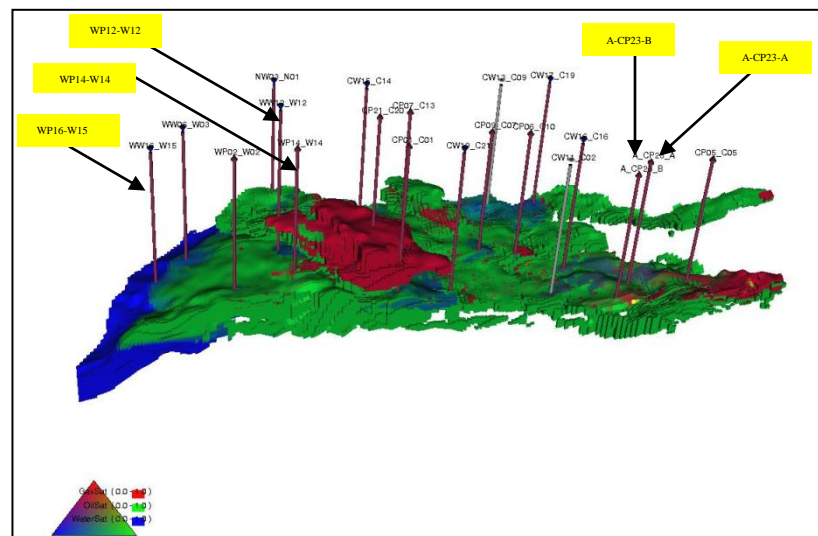


Figure 6.9 - Schiehallion field model (stage two – infill well drilling)

6.4.1 Reservoir simulation for infill well drilling

The five infill wells that were drilled after eight years of water flooding are listed below in Table 6.4.

| Well | Status | Completion type |
|----------|----------|-----------------|
| WP_W14 | Producer | Horizontal |
| A_CP23_A | Producer | Vertical |
| A_CP23_B | Producer | Vertical |
| WW12_W12 | Injector | Vertical |
| WW16_W15 | Injector | Vertical |

Table 6.4 - New infill wells drilled

Figure 6.10 shows the field oil production total with the new infill well drilling programme (WP_W14, A_CP23_A, A_CP23_B, WW12_W12 and WW16_W15), compared to the original water flooding scenario.

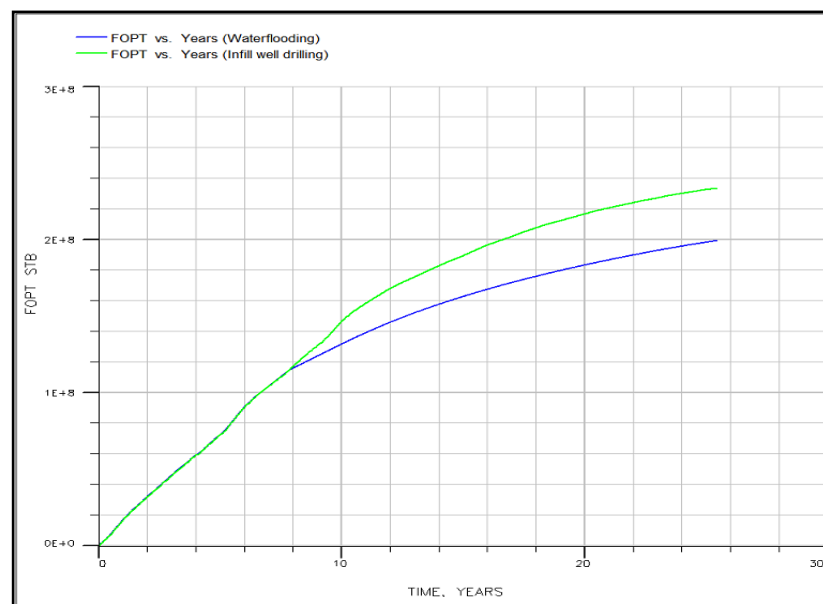


Figure 6.10 - Field oil production total for original well water flooding and for well infill well drilling programme

Figure 6.11 shows the field water injection total for the same two scenarios.

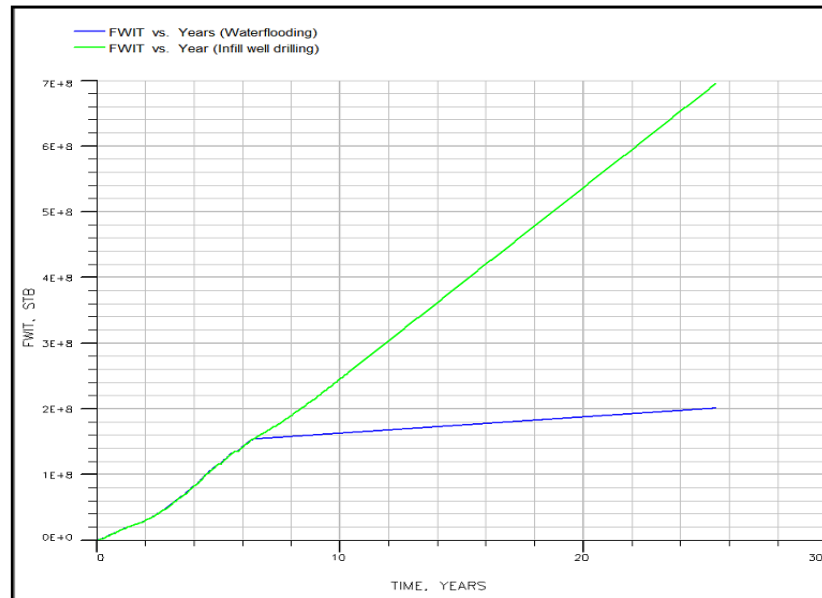


Figure 6.11 - Field water injection total for original well water flooding and for well infill well drilling programme

Figure 6.12 shows the field water production total for the two scenarios. The cumulative water injection volume is greater in the infill scenario than in the water flooding scenario, and there is a consequent increase in water production, but there is also a significant increase in oil recovery.

The value of the increased (and accelerated) oil production must therefore be offset against the increased cost of water handling (injection and production), as well as the cost of the new wells themselves.

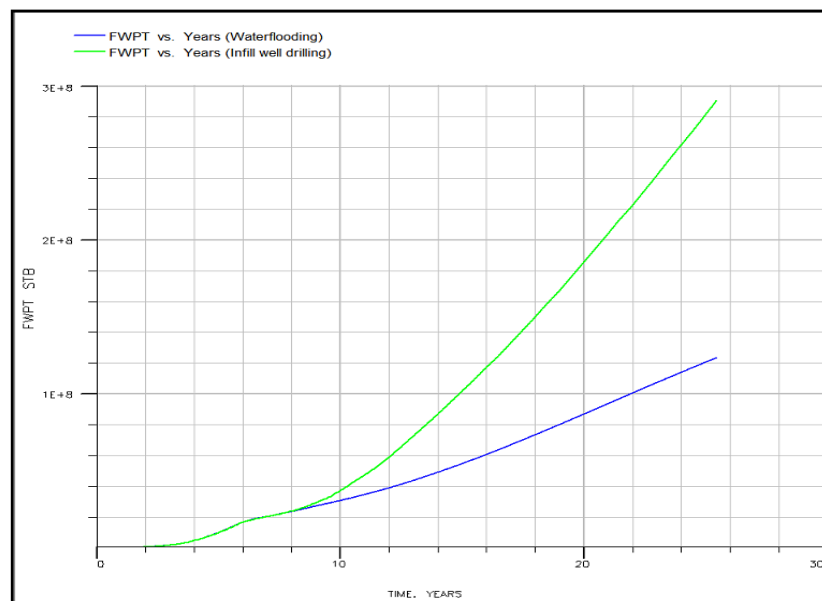


Figure 6.12 - Field water production total for original well water flooding and for well infill well drilling programme

6.4.2 Economic model for infill well drilling

The results that were obtained from reservoir simulation calculations for infill well drilling compared to water flooding, which are identified above in Section 6.4.1, were fed into the economic model as an input.

The output calculations are as follows;

- Incremental cash flow (ICF)
- Derived performance measures
 - Net present value (NPV)
 - Maximum capital outlay (MCO)
 - Net present value Index (NPVI)

The ranges for the variables that are used to assess the design, using project profitability measures as the decision making tool in the economic model of the infill well drilling scenarios, are given in Table 6.5.

| | Waterflooding | Infill well drilling |
|---|----------------------|-----------------------------|
| Duration of water flooding, years | 8 | 22 |
| New infill well drilling (producers) | - | 3 |
| New infill well drilling (injectors) | - | 2 |
| Well capital cost, mm\$/well | - | 15-20-25-30 |
| Well operating cost, mm\$/yr | - | 1.5-2-2.5-3 |
| Additional capital expenditure, mm\$ | - | - |
| Oil price, \$/bbl | 30-50-80-115-150 | 30-50-80-115-150 |
| Incremental oil production cost, \$/bbl | 8-10-12 | 8-10-12 |
| Water injection cost, \$/bbl | 1-2-3 | 1-2-3 |
| Water production cost, \$/bbl | 1-2-3 | 1-2-3 |

Table 6.5 - Ranges used for economic parameters for the infill well drilling sensitivities

6.4.3 Sensitivity and risk analysis for infill well drilling

Sensitivity analysis calculations for infill well drilling are developed to assess the future of engineering planning with regard to the reservoir simulation and the economics of infill well drilling projects. There were 2162 calculations for infill well drilling.

Figure 6.13 shows the net present value (NPV) on the Y-axis versus oil prices of 30, 50, 80, 115 and \$150/ bbl on the X-axis, with the impact of different well capital cost of 15, 20, 25 and 30 mm\$: discount rate of 10%, incremental oil price cost of \$8 /bbl, water injection cost of \$1 /bbl, water production cost of \$1 /bbl, and well operating cost of 1.5 mm\$. As can be seen, the highest Net Present Value (NPV) occurred in the scenario when the well capital cost was 15 mm\$, the lowest value. However, the main conclusion is that the overriding sensitivity of NPV is to oil price.

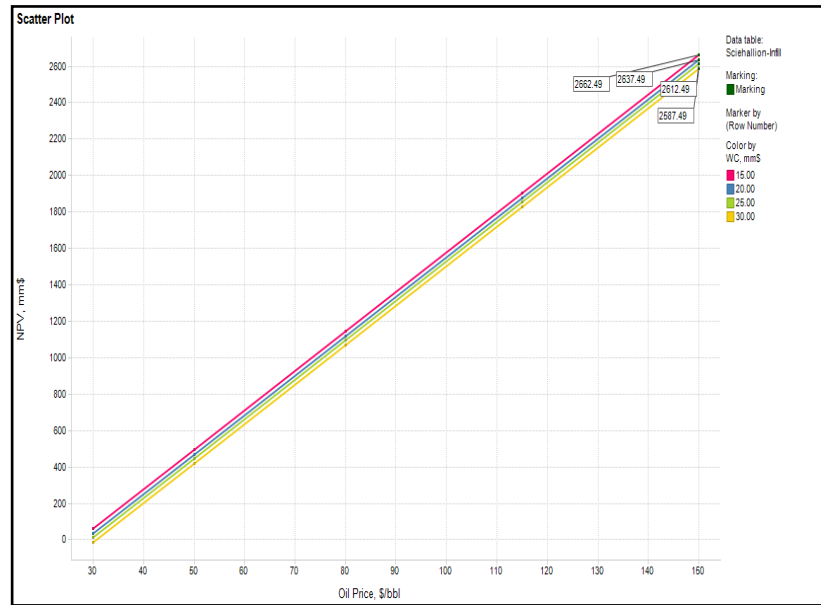


Figure 6.13 - NPV versus Oil prices at well capital cost of 15, 20, 25 and 30 MM\$
(Infill well drilling)

Figure 6. 14 shows the net present value (NPV) on the Y-axis versus oil prices of 30, 50, 80, 115 and \$150/ bbl on the X-axis, with identifying the impact of well capital cost of 15mm\$ and water injection cost of \$1, \$2 and \$3/bbl. All other parameters are the same as in Figure 6.10. As can be seen from the plot, the NPV decreases from 2662.49 mm\$ to 2229.31mm\$ when the water injection cost increases from \$1/bbl to \$3/bbl. Water injection cost has a higher impact on NPV than the other parameters such as water production cost and well operating cost in this infill well drilling scenario. This is a reflection of the significant increase in water injection volume identified in [Figure 6.9.

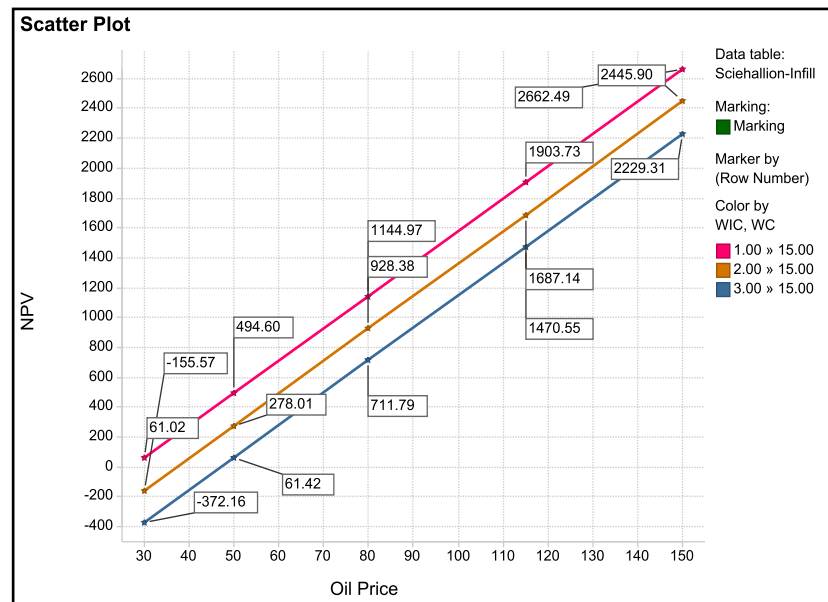


Figure 6. 14 - NPV versus Oil prices at well capital cost of 15MM\$ and water injection cost of \$1, \$2 and \$3/bbl. (Infill well drilling)

A total of 2162 economic calculations were performed, based on reservoir simulation output where 5 new infill wells were drilled (3 producers and 2 injectors) and compared to the base case where waterflooding was implemented. The results are summarised below in Table 6.6:

| Scenario | Statistics | Oil price \$/BBL | | | | |
|---------------------|---------------------|------------------|-------|--------|--------|--------|
| | | 30 | 50 | 80 | 115 | 150 |
| Infill welldrilling | Avg. (NPV), mm\$ | 326.9 | 106.6 | 757.0 | 1515.7 | 2274.5 |
| | Max. (NPV), mm\$ | 61.0 | 494.6 | 1144.9 | 1903.7 | 2662.4 |
| | StdDev. (NPV) | 190.1 | 190.1 | 190.1 | 190.1 | 190.1 |
| | Probability loss, % | 96 | 29 | 0.0 | 0.0 | 0.0 |

Table 6.6 - Statistical data for the infill well drilling sensitivity scenario based on 2162 economic calculation

6.5 Polymer flooding

6.5.1 Reservoir simulation for polymer flooding

The polymer data used in the method development work derived from (Sorbie, 2000) are described in Table 6.7 and Table 6.8.

| Polymer concentration (ppm) | Viscosity (cP) |
|-----------------------------|----------------|
| 400 | 4 |
| 800 | 10 |
| 1000 | 14 |
| 1200 | 19 |
| 1600 | 30 |

1 ppm = 4.259E-04 lb/stb

Table 6.7 - Viscosity versus concentration for polymer (Sorbie, 2000)

| Concentration (ppm) | Adsorption (microgram/gram) |
|---------------------|-----------------------------|
| 0 | 0.0 |
| 40 | 3.5 |
| 80 | 3.6 |
| 120 | 3.7 |
| 160 | 3.8 |
| 1000 | 3.8 |

Table 6.8 – Adsorption for HPAM – (polyacrylamide) (Sorbie, 2000)

The procedure for the reservoir simulation calculations is as follows:

12 sensitivities have been run with polymer concentrations: 200, 500, and 1000ppm and polymer timing of 1, 3, 5 and 10 years.

- Three contiguous stages (total time up to 23 years):
 - Stage 1: Water flood.
 - Stage 1 commences for three years.
 - Stage 2: Polymer flood.
 - Stage 2 lasts between 1 and 10years.
 - Stage 3: Water flood for up to 10 years, depending on WCT.

- The following output is generated;
 - Field oil production total (FOPT)
 - Field water production total (FWPT)
 - Field water injection total (FWIT)
 - Field polymer injection total (WCIT)
 - Field polymer production total (WCPT)

Figure 6.15 shows that the field oil production total during the polymer flood scenarios continues lower than the infill well drilling when the polymer concentration of 200 ppm for 1, 3, 5, and 10 years of polymer flood is used. The model then stopped running because the water cut exceeded the 98 % limitation.

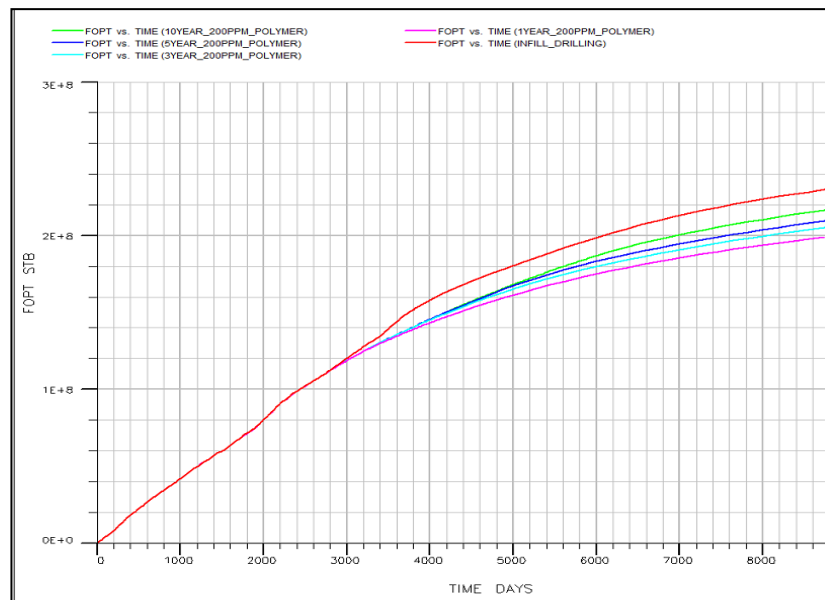


Figure 6.15 - Field oil production total for polymer concentration of 200 ppm

Figure 6.16 shows that the field water production total during the polymer flood scenarios continues lower than the infill well drilling case when the polymer concentration of 200 ppm is used for 1, 3, 5, and 10 years of polymer flooding. The least water production occurs when 10 years of polymer is injected.

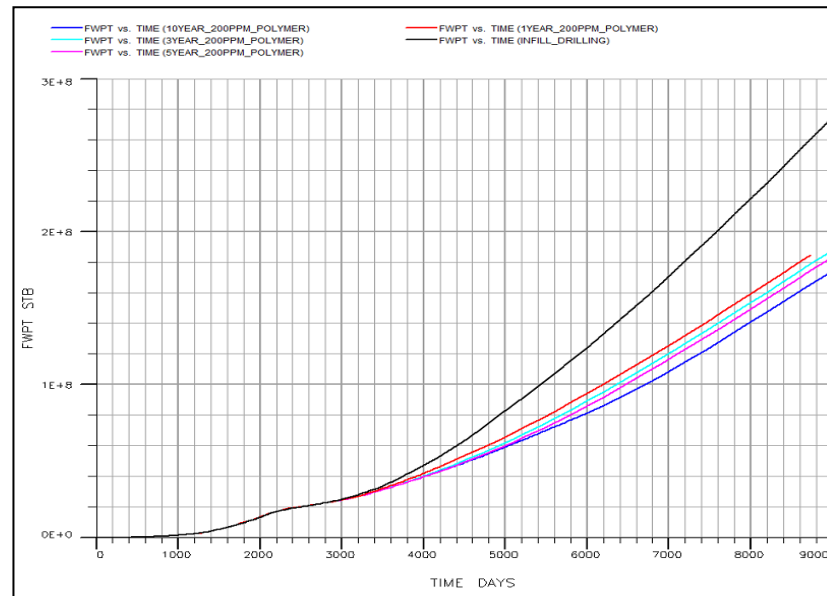


Figure 6.16 - Field water production total for polymer concentration of 200 ppm

Figure 6.17 shows that the field water injection total during the polymer flood scenarios when the polymer concentration of 200 ppm is used for 1, 3, 5, and 10 years of polymer flooding.

It is clear that the more polymer that is injected, the less water that is injected. This is not because polymer is replacing water, but because injectivity reduces due to the greater resistance of polymer to flow once it is in the reservoir. This is important, because as already noted, voidage replacement must be maintained to avoid pressure dropping below the bubble point. If this occurs, productivity may decline due to reduced oil mobility under three phase flow. Thus, to gain the benefit of reduced brine mobility with polymer injection, it may be necessary to consider upgrading of the injector facilities (pumps, perhaps additional wells) to maintain overall injectivity.

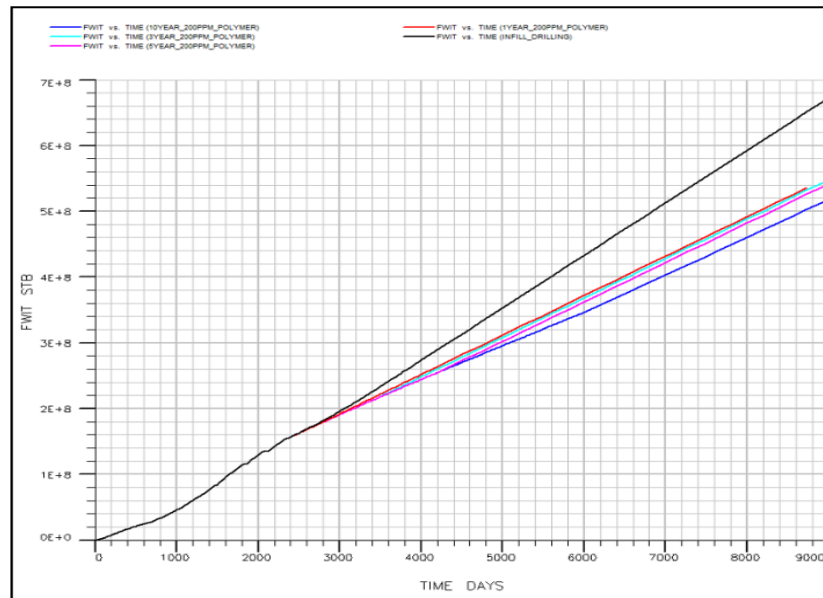


Figure 6.17 - Field water injection total for polymer concentration of 200 ppm

Figure 6.18 shows that the field oil production total during the polymer flood scenarios continues lower than the infill well drilling when the polymer concentration of 500 ppm is used for 1, 3, 5, and 10 years of polymer flooding. The oil production increases at the end of the 10 years of polymer injection, and approaches that achieved by infill well drilling. The model then stopped running because the water cut exceeded the 98 % limitation.

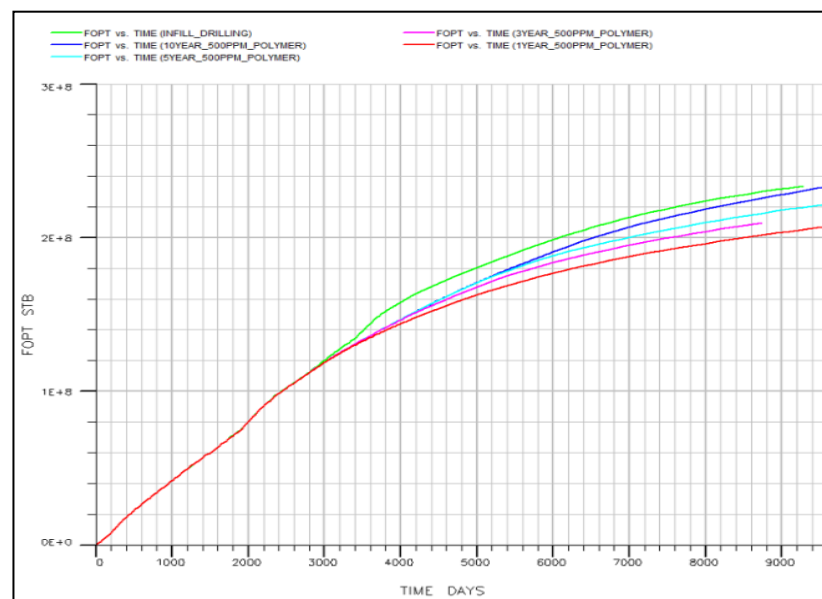


Figure 6.18 - Field oil production total for polymer concentration of 500 ppm

Figure 6.19 shows that the field water production total during the polymer flood scenarios is lower than the infill well drilling case when the polymer concentration of 500 ppm is used for 1, 3, 5, and 10 years of polymer flooding, and is lower than the equivalent case for 200 ppm polymer concentration (as in Figure 6.16).

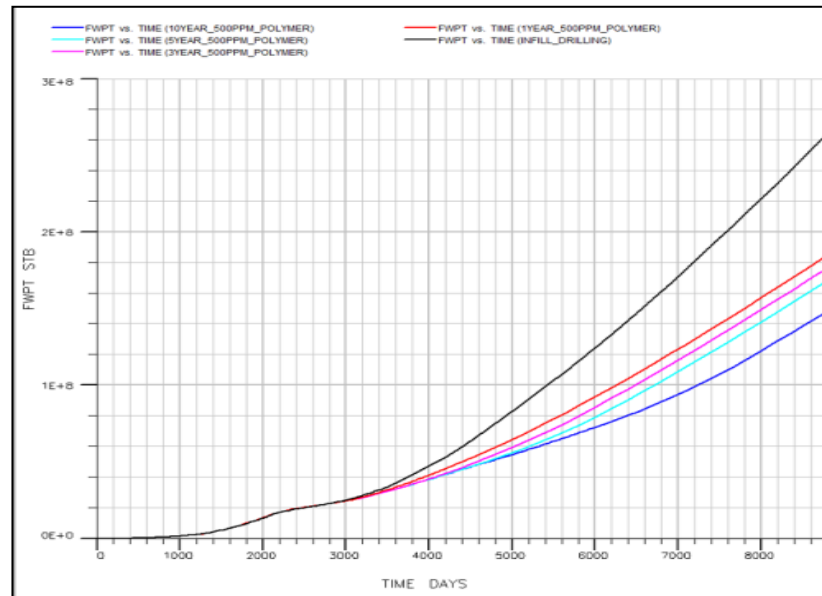


Figure 6.19 - Field water production total for polymer concentration of 500 ppm

Figure 6.20 shows the field water injection total during the polymer flood scenarios when the polymer concentration of 500 ppm is used for 1, 3, 5, and 10 years of polymer flooding, and again the values are lower than the corresponding values for 200 ppm polymer injection.

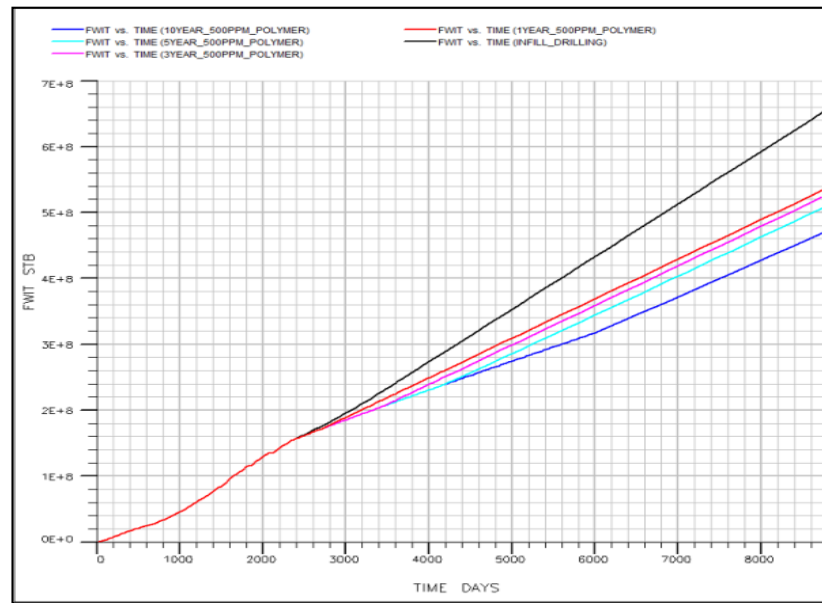


Figure 6.20 - Field water injection total for polymer concentration of 500 ppm

Figure 6.21 to Figure 6.23 are equivalent for scenarios where polymer concentrations of 1000 ppm are used. All trends continue in the same progression as when comparing 500 ppm concentrations with the 200 ppm cases. The only significant item to note is that the final oil recovery only exceeds the infill well drilling scenario where polymer injected at a concentration of 1000 ppm is for 10 years, but that even in this case a significant volume of oil production is deferred relative to the infill well scenario. However, it is worth noting that the cumulative water produced during the polymer flood is more than halved in this case, and this would result in some cost savings. Thus, if upgrading injection facilities to maintain injectivity is considered, significantly more oil may be recovered than in the infill well drilling scenarios.

Thought should be given to the impact of cost savings associated with lower volumes of water being produced, and the impact that the cost per barrel of produced water has on the overall project economics.

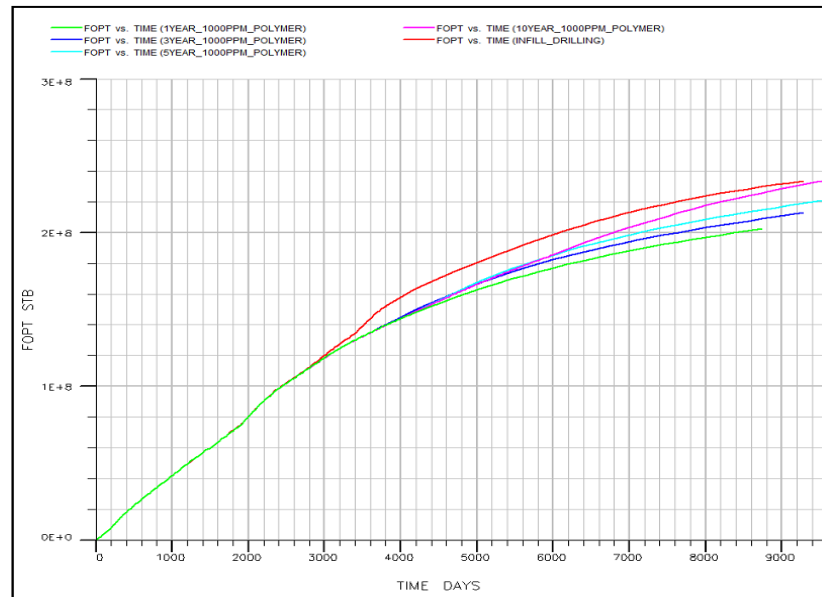


Figure 6.21 - Field oil production total for polymer concentration of 1000 ppm

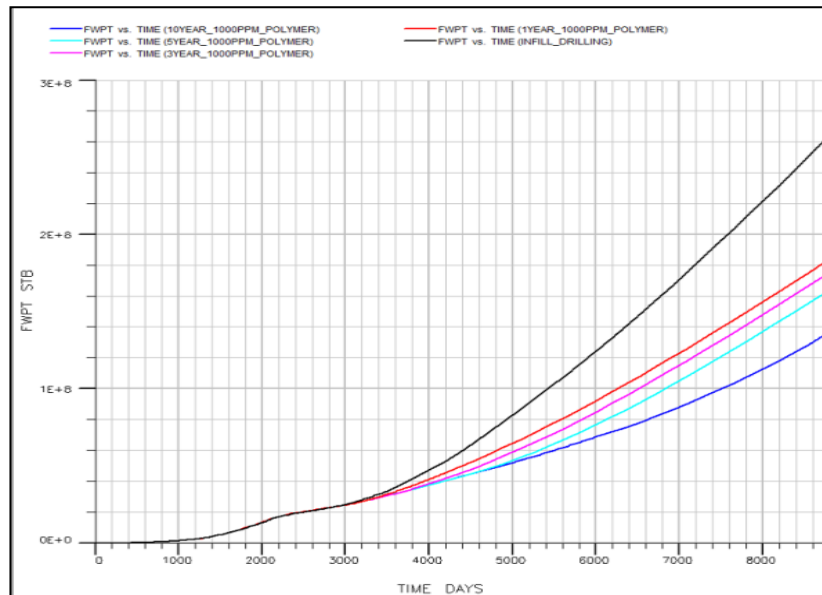


Figure 6.22 - Field water production total for polymer concentration of 1000 ppm

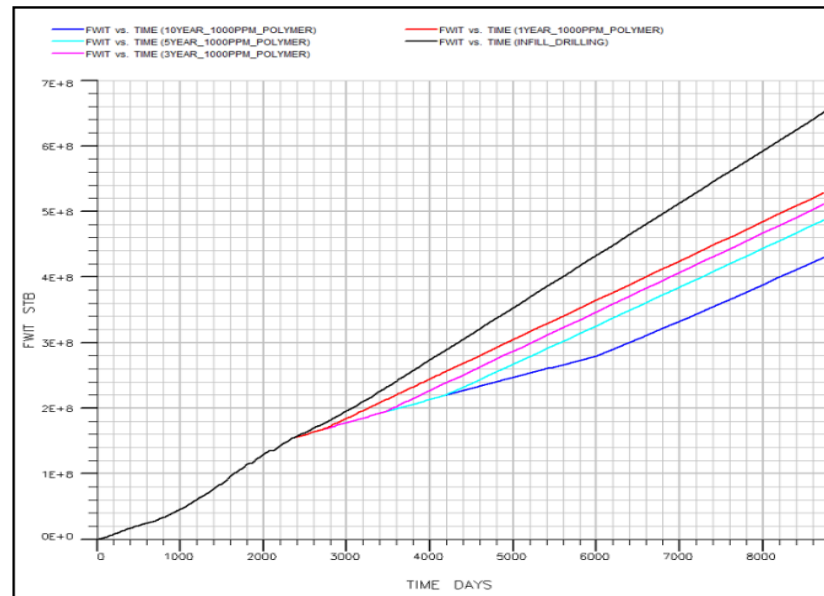


Figure 6.23 - Field water injection total for polymer concentration of 1000 ppm

6.5.2 Economic model for polymer flooding

The procedure for the economic model is as follows:

- Input
 - Results of reservoir simulation calculations (identified above)
 - Economic parameters: Polymer concentration, oil price, incremental oil production cost (IOPC), water injection cost (WIC), water production cost (WPC), polymer cost (PC), incremental polymer production cost (IPPC), incremental polymer injection cost (IPIC).
- Output
 - Incremental cash flow (ICF)
 - Derived performance measures
 - Net present value (NPV)
 - Maximum capital outlay (MCO)

The range of variables that are used to assess the design, using project profitability measures as the decision making tool in the economic model of the polymer flooding scenarios are given in Table 6.9.

| | Water flooding | Polymer flooding |
|---|-----------------------|-------------------------|
| Duration of water flooding, years | 3 | 1 to 22 |
| Duration of polymer flooding, years | - | 1 -2-3-10 |
| Additional capital expenditure, mm\$ | - | 8-11-18-31 |
| Polymer concentration, ppm | - | 100-200-500-1000 |
| Oil Price, \$/bbl | 30-50-80-115-150 | 30-50-80-115-150 |
| Incremental oil production cost, \$/bbl | - | 8-10-12 |
| Water injection cost, \$/bbl | - | 1-2-3 |
| Water production cost, \$/bbl | - | 1-2-3 |
| Polymer cost, \$/lb | - | 1-2-3-4 |
| Incremental polymer production cost, \$/bbl | - | 0-0.5-1 |
| Incremental polymer injection cost, \$/bbl | - | 0.25-0.5-1 |

Table 6.9 - Ranges used for economic parameters for the polymer flooding sensitivities

6.5.3 Sensitivity and risk analysis for polymer flooding

12 sensitivities have been run with polymer concentrations: 200, 500, and 1000ppm and polymer injection duration of 1, 3, 5 and 10 years. The output results from these reservoir simulations were fed into the economic model where 58322 calculations were performed. Analysis of the polymer flooding scenarios was developed to assess the future engineering planning requirements using the reservoir simulation output and the economics calculations.

Figure 6.24 shows the relation between NPV and polymer concentration at an oil price of \$30 with economic parameters set as follows:; IOPC \$8/bbl; WIC \$1/bbl; WPC \$1/bbl; PC \$1/lb; IPPC \$0/bbl; IPIC \$0.25/bbl. The observations from the graph are as follows:

1. At a \$30 oil price, as concentration increases NPV rises then falls.
2. The later the start in polymer flooding, the lower the NPV.
3. The more years of polymer flooding, the higher the NPV.
4. Negative NPV occurs if polymer is injected for fewer than 3 years.

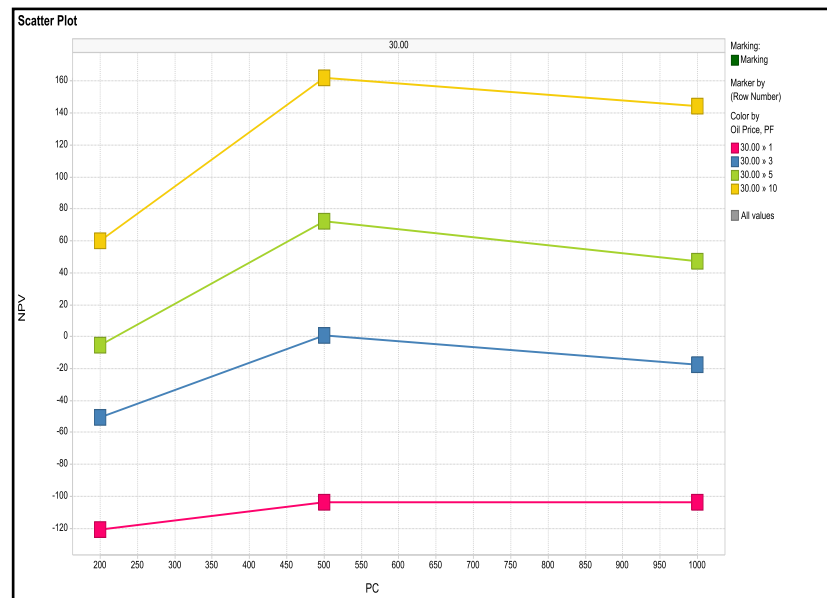


Figure 6.24 - Net present value versus polymer concentrations at oil price of \$30/bbl. On the x-axis is polymer concentration, on the y-axis is NPV. Each line is for a different number of years of polymer flooding (1, 3, 5 and 10).

Figure 6.25 shows the relation between net present value and polymer concentration at an oil price of \$150/bbl with the other economic parameters set as above. The observations we make from this graph are as follows:

1. At this high oil price NPV rises, as concentration increases from 100 ppm to 500 ppm and then falls at polymer concentration of 1000 ppm.
2. Polymer concentration of 500 ppm is the optimal.
3. The later the start in polymer flooding, the lower the NPV.
4. The more years of polymer flooding, the higher the NPV.
5. All the NPV values are positive.

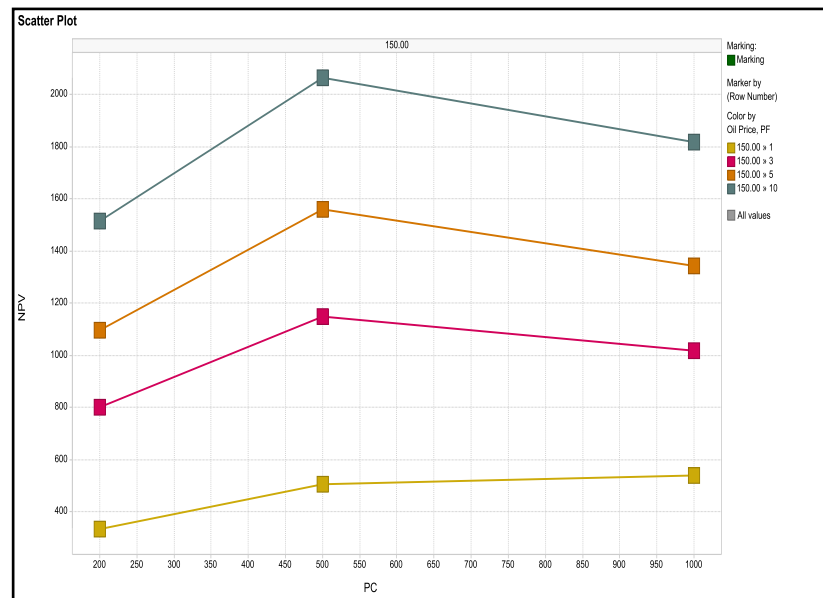


Figure 6.25 - Net present value vs. polymer concentrations at oil price of \$150/bbl. On the x-axis is polymer concentration, on the y-axis is NPV. Each line is for a different number of years of polymer flooding (1, 3, 5 and 10).

Figure 6.26 shows the relation between NPV and polymer concentration for all different oil prices of \$30, \$50, \$80, \$115, and \$150/bbl with other economic parameters set as previously. As before, the polymer concentration of 500 ppm is the optimum concentration since above this concentration the NPV decreases in all polymer flooding scenarios of 3, 5 and 10 years and is almost constant at 1 year polymer flooding.

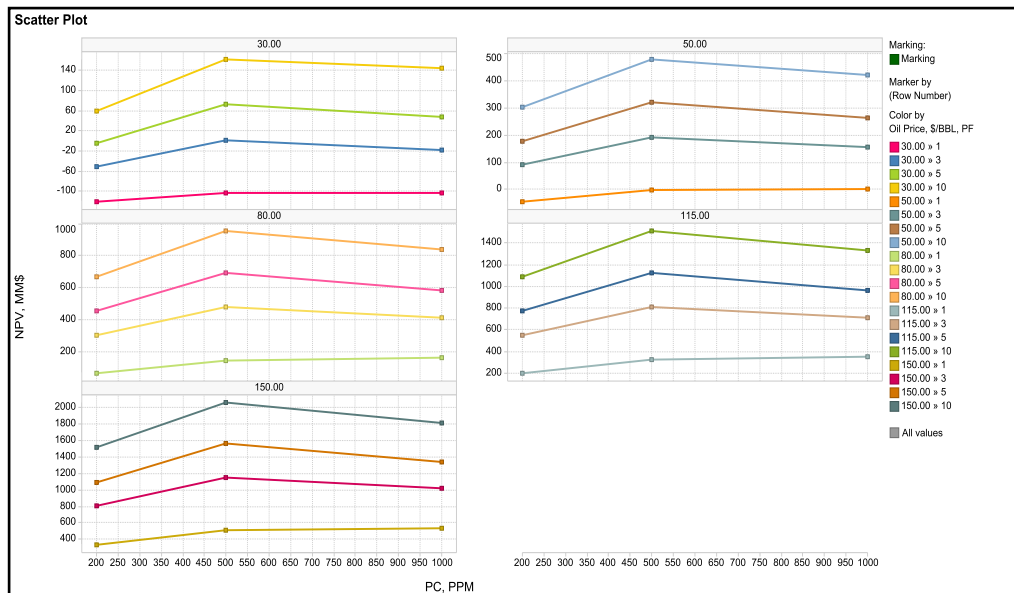


Figure 6.26 - Net present value vs. polymer concentrations at different oil prices; each graph is for a different oil price (\$30, \$50, \$80, \$115, and \$150/bbl). On the x-axis is polymer concentration, on the y-axis is NPV. Each line is for a different number of years of polymer flooding (1, 3, 5 and 10).

Figure 6.27 shows the impact of water injection cost on net present values from different polymer flooding periods at the low oil price of \$30/bbl. As can be seen from the graph, increasing the water injection cost from \$1/bbl to \$3/bbl has a large impact on NPV at this low oil price of \$30/bbl. This is a (positive) consequence of the reduced injectivity during polymer flooding. The NPV are negative for polymer flooding periods between 1 and 3 years at a water injection cost of \$1/bbl, while the NPV are negative for all scenarios at water injection cost of \$3/bbl.

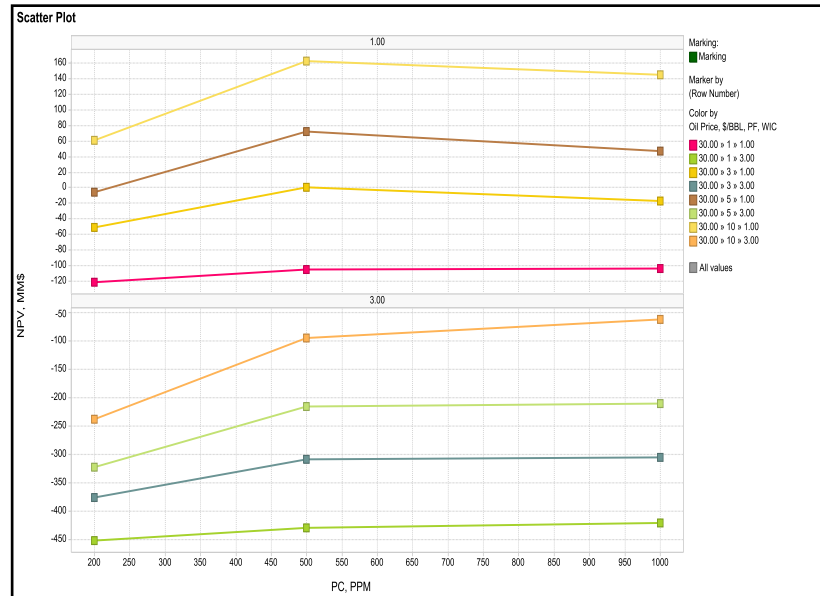


Figure 6.27 - Net present value vs. polymer concentrations at oil price of \$30/bbl, years of polymer flooding and water injection cost (\$1, and \$3/bbl). Each line is for a different number of years of polymer flooding (1, 3, 5 and 10).

Figure 6.28 shows the impact of water injection cost on net present values for different polymer flooding periods at a high oil price of \$150/bbl. As can be seen from the graph, increasing the water injection cost from \$1/bbl to \$3/bbl decreases the net present values, but the relative impact is less than for an oil price of \$30/bbl. The net present values are all positive for all polymer flooding periods of 1, 3, 5 and 10 years at water injection costs of \$1/bbl and \$3/bbl.

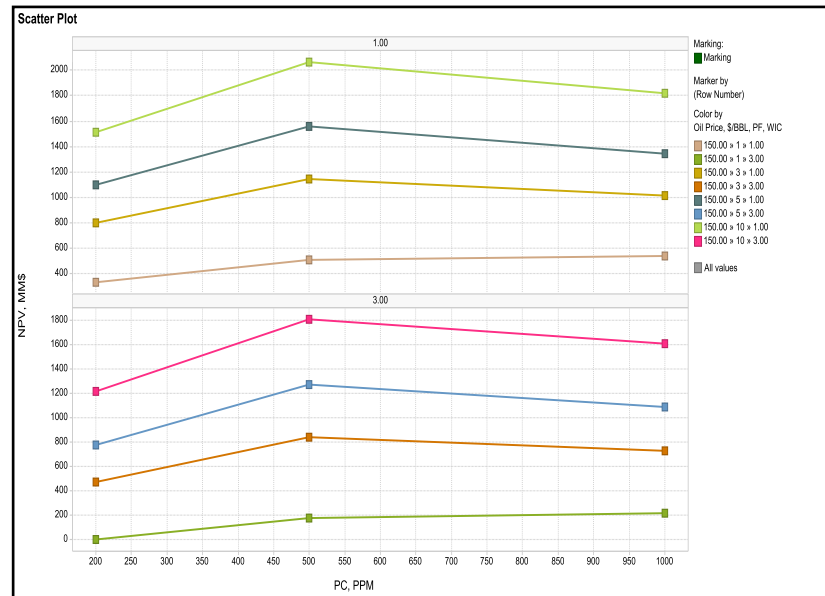


Figure 6.28 - Net present value vs. polymer concentrations at oil price of \$150/bbl for various years of polymer flooding and water injection costs (\$1/bbl and \$3/bbl). Each line represents years of polymer flooding.

Figure 6.29 shows the impact of incremental polymer injection cost on net present values for different polymer flooding periods with an oil price of \$30/bbl. Increasing the incremental polymer injection cost from \$0.25/bbl to \$1/bbl has a large impact on net present values at this low oil price. The net present values are negative for polymer flooding periods up to 5 years when the incremental polymer injection cost is increased from \$0.25/bbl to \$1/bbl.

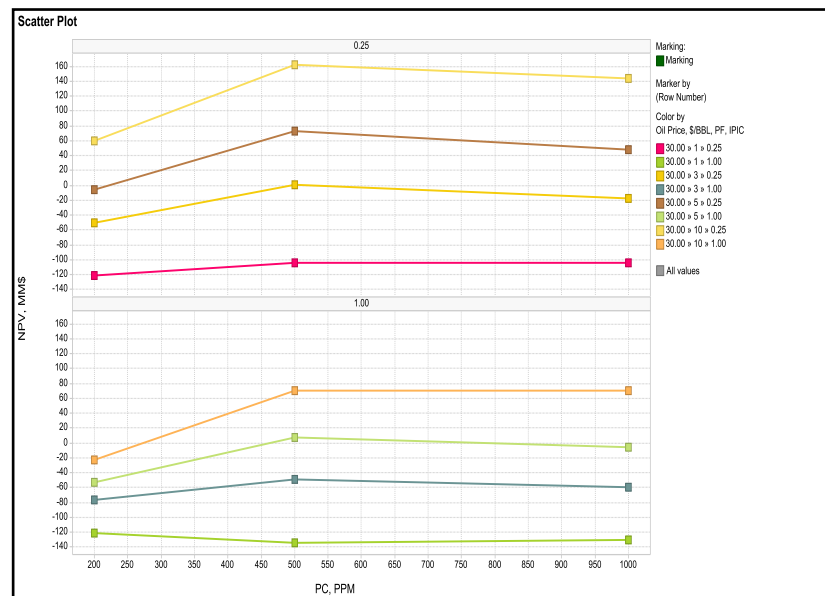


Figure 6.29 - Net present value vs. polymer concentrations at oil price of \$30/bbl, (1, 3, 5 and 10) years of polymer flooding and incremental polymer injection cost (\$0.25/bbl and \$1/bbl). Each line is for a different number of years of polymer flooding.

Figure 6.30 shows the impact of incremental polymer injection cost on net present values at different polymer flooding periods with an oil price of \$150/bbl. Increasing the incremental polymer injection cost from \$0.25/bbl to \$1/bbl has almost no impact on net present values at higher oil prices.

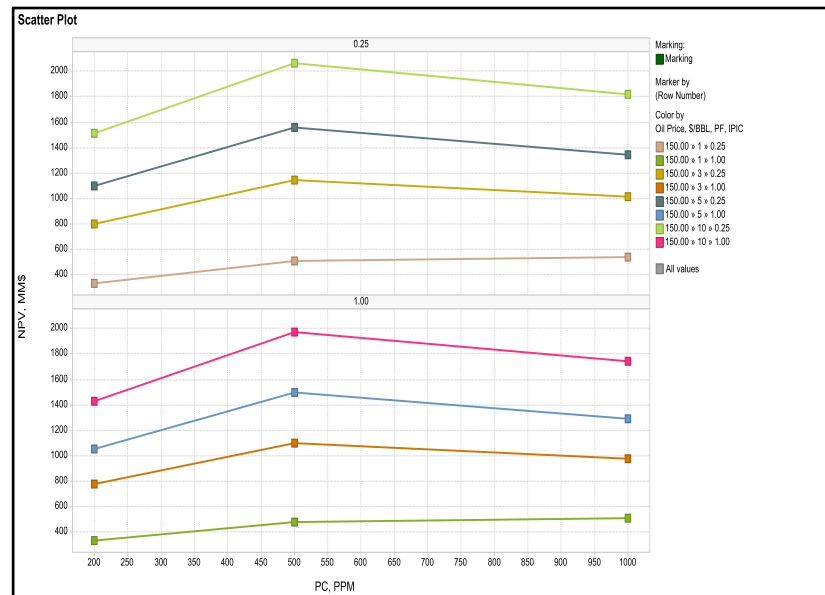


Figure 6.30 - Net present value vs. polymer concentrations at oil price of \$150/bbl for various years of polymer flooding and incremental polymer injection costs (\$0.25/bbl and \$1/bbl). Each line is for a different number of years of polymer flooding (1, 3, 5 and 10).

A total of 58322 economic calculations were performed, based on reservoir simulation output. 12 sensitivities have been run with polymer concentrations of 200, 500, and 1000 ppm and polymer injection duration of 1, 3, 5 and 10 years that compared to the base case where waterflooding was implemented and the results are summarised below in Table 6.10.

- At \$30 oil price, as concentration increases NPV rises then falls.
 - The more years of polymer flooding, the higher the NPV.
 - Negative NPV occurs for polymer injection between 1 and 3 years
- At this high oil price, as concentration increases from 100 ppm to 500 ppm NPV rises, but then falls at polymer concentration of 1000 ppm.

- Polymer concentration of 500 ppm is the optimal.
- The more years of polymer flooding, the higher the NPV.
- All the NPV values are positive

| Oil Price, \$/bbl | statistics | 200 ppm | 200 ppm | 200 ppm | 200 ppm | 500 ppm | 500 ppm | 500 ppm | 500 ppm | 1000 ppm | 1000 ppm | 1000 ppm | 1000 ppm |
|-------------------|------------------------|---------|---------|---------|---------|---------|---------|---------|---------|----------|----------|----------|----------|
| | | 1 year | 3 year | 5 year | 10 year | 1 year | 3 year | 5 year | 10 year | 1 year | 3 year | 5 year | 10 year |
| 30 | Avg(NPV), mm\$ | -321.5 | -263.0 | -225.2 | -168.9 | -316.9 | -217.0 | -165.2 | -50.1 | -311.1 | -218.2 | -142.7 | -26.3 |
| | StdDev(NPV) | 136.9 | 134.8 | 132.6 | 128.6 | 135.4 | 129.8 | 124.5 | 114.7 | 131.6 | 120.4 | 109.5 | 92.3 |
| | Probability of loss, % | 99 | 97 | 96 | 91 | 99 | 95 | 91 | 67 | 99 | 96 | 90 | 61 |
| 50 | Avg(NPV), mm\$ | -245.8 | -121 | -41.4 | 73.5 | -215.3 | -25.9 | 82.8 | 266.8 | -204.1 | -45.9 | 73.2 | 252.4 |
| | StdDev(NPV) | 136.9 | 134.8 | 132.6 | 128.6 | 135.4 | 129.8 | 124.5 | 114.7 | 131.6 | 120.4 | 109.5 | 92.3 |
| | Probability of loss, % | 96 | 82 | 62 | 28 | 94 | 58 | 25 | 1 | 94 | 65 | 25 | 0 |
| 80 | Avg(NPV), mm\$ | -132.3 | 92.1 | 234.1 | 437.2 | -62.8 | 260.6 | 454.9 | 742.3 | -43.7 | 212.3 | 397.3 | 670.5 |
| | StdDev(NPV) | 136.8 | 134.8 | 132.6 | 128.6 | 135.4 | 129.8 | 124.5 | 114.7 | 131.6 | 120.4 | 109.5 | 92.3 |
| | Probability of loss, % | 83 | 4 | 0.04 | 0 | 68 | 2 | 0 | 0 | 63 | 4 | 0 | 0 |
| 115 | Avg(NPV), mm\$ | 0.1 | 340.7 | 555.7 | 861.6 | 115.1 | 595.0 | 889.0 | 1297.0 | 143.4 | 513.7 | 775.3 | 1158.2 |
| | StdDev(NPV) | 136.9 | 134.8 | 132.6 | 128.6 | 135.4 | 129.8 | 124.5 | 114.7 | 131.6 | 120.4 | 109.5 | 92.3 |
| | Probability of loss, % | 50 | 1 | 0 | 0 | 20 | 0 | 0 | 0 | 14 | 0 | 0 | 0 |
| 150 | Avg(NPV), mm\$ | 132.5 | 589.3 | 877.2 | 1286.0 | 293.0 | 929.4 | 1323.1 | 1851.7 | 330.5 | 815.1 | 1153.3 | 1646.0 |
| | StdDev(NPV) | 136.9 | 134.8 | 132.6 | 128.6 | 135.4 | 129.8 | 124.5 | 114.7 | 131.6 | 120.4 | 109.5 | 92.3 |
| | Probability of loss, % | 17 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 1 | 0 | 0 | 0 |

Table 6.10 - Statistical data for polymer flooding sensitivity scenarios based on 58322 economic calculations

6.6 Incremental net present value (INPV)

The objective of this study is to develop a decision making tool to choose whether to undertake infill well drilling or polymer flooding, not only in terms of maximising oil recovery but also in terms of the estimated return on investment ($\text{Cash Flow} = \text{Revenue} - \text{Capital expenditure} - \text{Operating expenditure}$). In this regard, the economic models were previously developed for both recovery techniques.

Sets of sensitivity data have been generated from reservoir simulation calculations for both recovery techniques and then fed into the economic models independently. There were 2162 calculations for infill well drilling and 58322 for polymer flooding, respectively. The sets of data for both recovery techniques do not use all the same economic variables. In fact there are only four common variables that are used in assessing both techniques: oil price, incremental oil production cost, water injection cost and water production cost. There are four economic parameters used only in analysis of polymer flooding: polymer cost, (polymer concentration not used explicitly), incremental polymer production cost, incremental polymer injection cost, and years of polymer injection. There are two economic parameters used only for infill well drilling analysis: well operating cost and well capital cost. Table 6.11 show that there are a total of 933,120 combinations of infill well drilling and polymer flooding scenarios to compare. This is computed by overlapping the two sets by making sure that the intersection is held constant and every combination of the two unique sets of variables is made.

The power of this approach lies in the fact that it is a systematic method to compare all computed polymer flooding scenarios with all infill well scenarios, and test the sensitivity to individual parameters, be they common parameters, such as oil price or water production cost, or be they specific parameters, such as polymer cost, or new well capital cost.

In general, the breadth of the comparison could be significantly extended by including a wider range of sensitivities to reservoir engineering parameters, such as uncertainties in reservoir description (which would affect both recovery techniques), other options for polymer flooding (say longer periods of polymer injection) and other infill well drilling options, such as other well locations.

| | | |
|-------------------------|---|--------|
| Common variables | Present oil Price | 5 |
| | Present incremental oil production cost | 3 |
| | Present water injection cost | 3 |
| | Present water production cost | 3 |
| | Total | 135 |
| | | |
| Polymer only | Present polymer cost | 4 |
| | Polymer concentration (not used explicitly) | 3 |
| | Present incremental polymer production cost | 3 |
| | Present incremental polymer injection cost | 3 |
| | Years of polymer injection | 4 |
| | Total | 432 |
| | | |
| Infill only | Well operating cost | 4 |
| | Well capital cost | 4 |
| | Total | 16 |
| | | |
| | | 933120 |

Table 6.11 - Total number of incremental net present values between infill well drilling and polymer flooding

Figure 6.31 and Figure 6.32 show that in these calculations in general infill well drilling generates higher incremental net present value than polymer flooding.

(Positive values of INPV here represent the situation where infill well drilling outperforms polymer flooding, and negative values the opposite). The interpretation from the plot is as follows.

Infill well drilling generates greater and earlier production of oil, and the higher the oil price the more valuable in this incremental revenue. Regardless of what happens to the well cost, at high oil price infill well drilling performs better because it generates more revenue due to the higher oil production early on. However, at low oil prices, the cost of drilling new wells could make polymer flooding a more viable option. For higher well costs, particularly at low oil prices, polymer flooding may be better.

Of course, at low oil prices, as noted earlier, other operating costs, such as water handling costs, have more of an impact on the overall economics.

At \$30/bbl oil price polymer flooding is more beneficial whereas at an oil price of \$80/bbl infill well drilling is better, with the cut off being about \$50/bbl. There is always a slight sensitivity to well cost, with higher well cost favouring polymer flooding, but the sensitivity to oil price is greater.

The cost of drilling new wells in early stages of the project is what gives a higher CAPEX than the polymer flooding. Infill well drilling also gives higher oil production at early stages of the project. At high oil prices that early oil production has a large impact because of the discount factor compared to the later production from polymer flooding. At lower discount rate this affect might not be so evident.

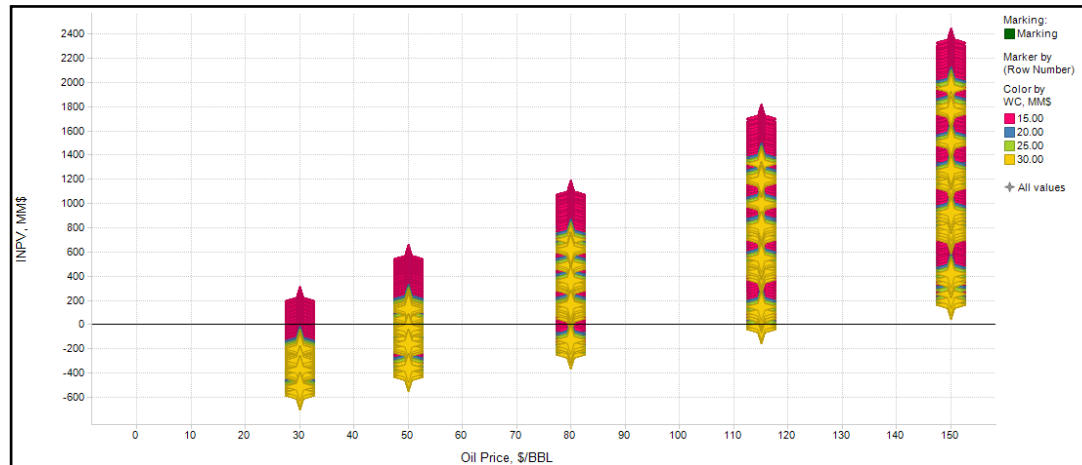


Figure 6.31 – Incremental net present value based on 933120 calculations comparing infill well drilling and polymer flooding at different well cost (15, 20, 25 and 30 mm\$) and for various oil prices.

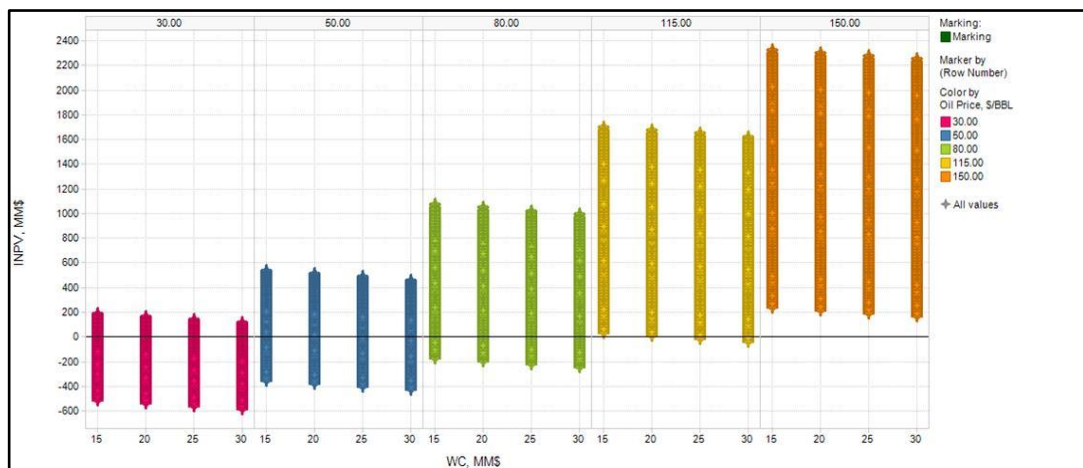


Figure 6.32 – INPV based on 933120 calculations comparing infill well drilling and polymer flooding at different well cost (15, 20, 25 and 30 mm\$) and for various oil prices.

Figure 6.33 shows that the polymer flooding outperforms infill well drilling in the many scenarios since it has lower maximum capital outlay (MCO). This is due to the significant upfront well capital cost. The higher the well cost, the more polymer outperforms infill well drilling using this measure in this case.

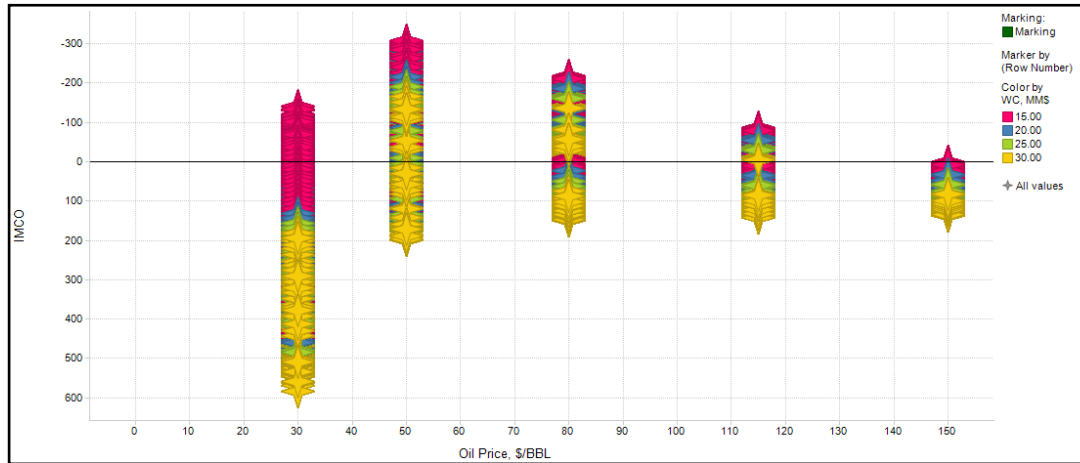


Figure 6.33 - Incremental maximum capital outlay (IMCO) based on 933120 calculation as a function of contrasting oil prices between infill well drilling (where positive is better) and polymer flooding (where negative is better) at different well costs (15, 20, 25 and 30 mm\$)

Figure 6.34 shows that the incremental net present index increases as the oil price increases. At higher oil price, the range of the investment efficiency is from -23.9 to 23.2, so the best investment efficiency of the infill well drilling scenarios is 23.2, and the best that polymer outperforms infill well drilling using INPVI is 23.9. At low well capital cost the investment efficiency of infill well drilling performs very similar to polymer flooding because of the early extra production and low well cost, while at high well capital cost polymer outperforms because of the extra cost early in the project.

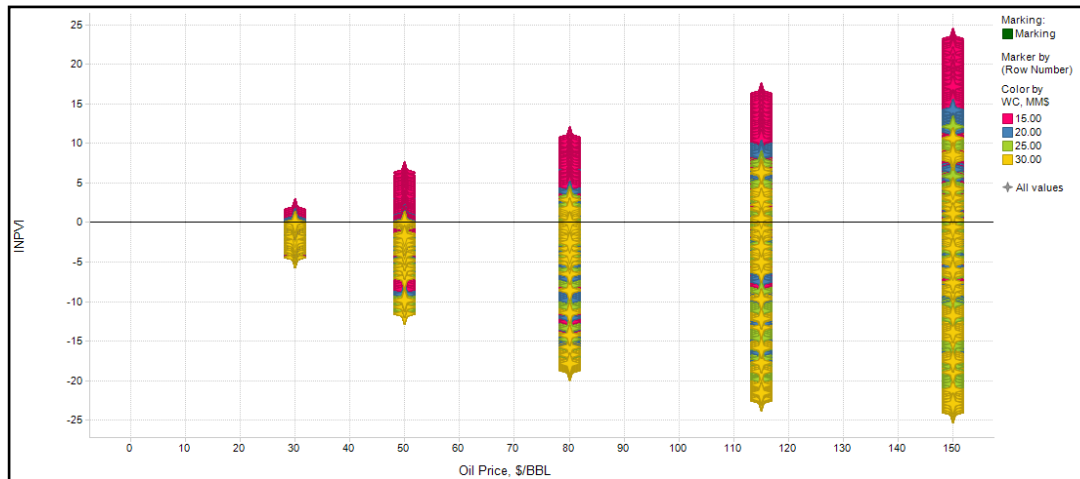


Figure 6.34 - Incremental net present value index (INPVI) based on 933120 calculation as a function of oil prices comparing between infill well drilling and polymer flooding at different well costs (15, 20, 25 and 30 mm\$)

Figure 6.35 shows the incremental net present value of all the calculation as a function of oil prices comparing infill well drilling and polymer flooding at different timings of polymer flooding (1, 3, 5 and 10 years). If it is above zero, infill well drilling generates greater INPV, and if it is below zero polymer flooding generates greater INPV.

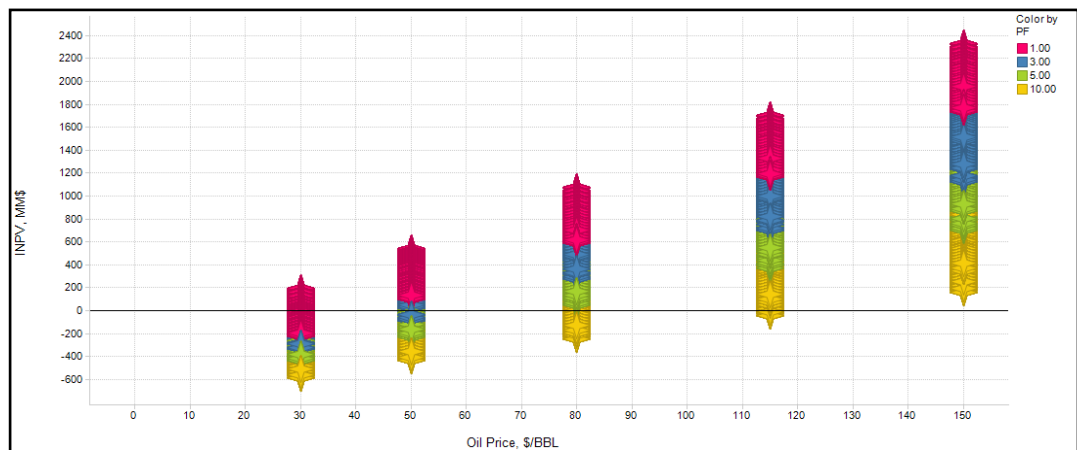


Figure 6.35 - Incremental net present value based on 933120 calculation as a function of oil prices comparing between infill well drilling and polymer flooding at different well costs (15, 20, 25 and 30 mm\$)

6.7 Polymer flooding in addition to infill well drilling

6.7.1 Reservoir simulation for polymer flooding in addition to infill well drilling

The same reservoir simulation procedure that was implemented for either infill well drilling or polymer flooding individually is now applied in the same field, but where polymer is injected in addition to an infill well drilling programme (five additional wells, 3 producers and 2 injectors) to maximise oil recovery.

As noted above, addition of polymer reduces the mobility of the injected brine, and hence injectivity is reduced, and hence it is to be expected that a polymer flooding strategy may require additional wells to boost the injection capacity.

Three reservoir simulation sensitivities have been run with polymer concentrations of: 200, 500, and 1000ppm with polymer injected for 10 years.

- Three contiguous stages (total time up to 23 years):
 - Stage 1: Water flood.
 - Stage 1 commences for three years.
 - Stage 2: Polymer flood.
 - 10 years.
 - Stage 3: Water flood for up to 10 years, depending on WCT.
- The following output is generated;
 - Field oil production total (FOPT)
 - Field water production total (FWPT)
 - Field water injection total (FWIT)
 - Field polymer injection total (WCIT)
 - Field polymer production total (WCPT)

Figure 6.36 shows that field oil production total during the polymer injection for 10 years at different polymer concentrations of 200, 500 and 1000 ppm, in addition to the five new infill well drilling scenarios. The oil production from polymer injection with different concentrations in addition to infill well drilling is higher than the infill well drilling only scenario, which is represented by the dotted green dark line. As can be also seen, the 500 ppm scenario has the higher oil recovery compared to the other polymer

concentrations. The model then stopped running because the water cut exceeded the 98 % limit.

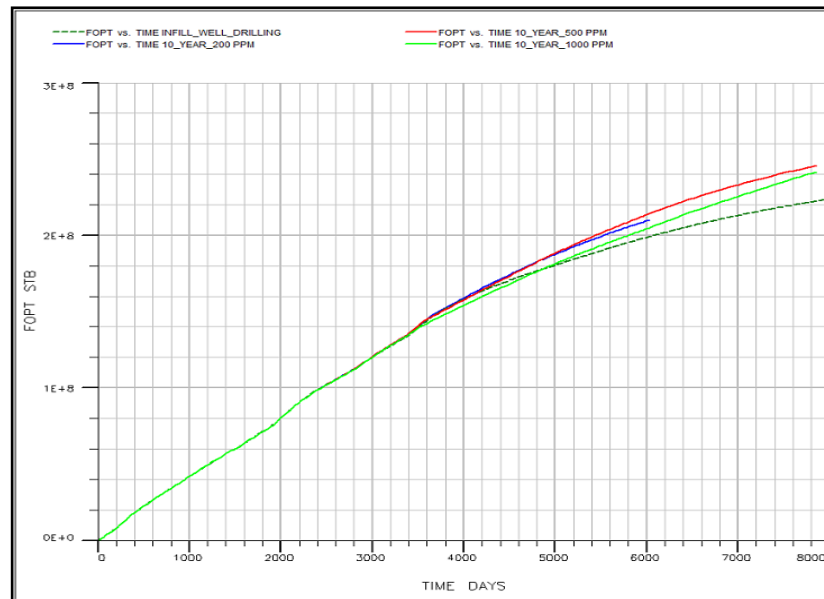


Figure 6.36 - Field oil production total for the combination of infill well drilling and polymer, at 10 years polymer injection with concentration of 200, 500 and 1000 ppm

Figure 6.37 shows that the field water production total during the polymer injection for 10 years at different polymer concentration 200, 500 and 1000 ppm, in addition to new five infill wells drilling scenario. Infill well drilling scenario has a higher water production total compared to polymer injection in addition to the five new infill well drilling scenario.

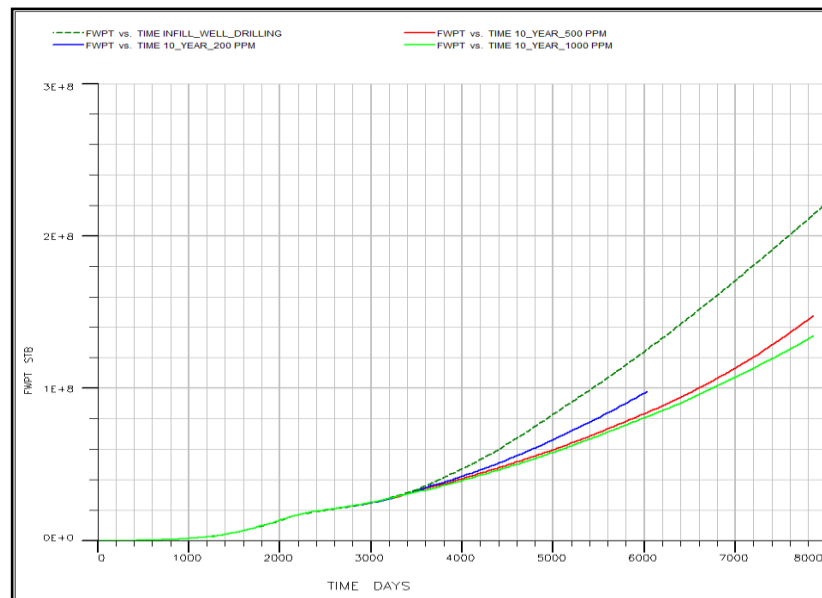


Figure 6.37 - Field water production total for the combination of infill well drilling and polymer, at 10 years polymer injection with concentration of 200, 500 and 1000 ppm

Figure 6.38 shows that the field water injection total during the polymer injection for 10 years at different polymer concentration 200, 500 and 1000 ppm, in addition to new five infill wells drilling scenario.

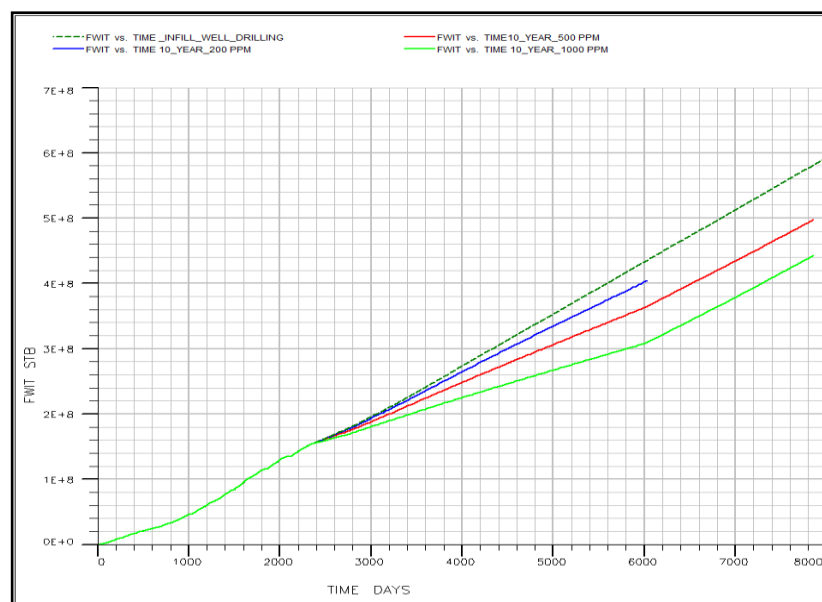


Figure 6.38 - Field water injection total for the combination of infill well drilling and polymer, at 10 years polymer injection with concentration of 200, 500 and 1000 ppm

6.7.2 Economic model for polymer flooding in addition to infill wells drilling

The procedure for the economic model is as follows:

- Input
 - Results of reservoir simulation calculations (identified above)
 - Economic parameters: Polymer concentration, oil price, incremental oil production cost (IOPC), water injection cost (WIC), water production cost (WPC), polymer cost (PC), incremental polymer production cost (IPPC), incremental polymer injection cost (IPIC).
- Output
 - Incremental cash flow (ICF)
 - Derived performance measures
 - Net present value (NPV)
 - Maximum capital outlay (MCO)

The range of variables that are used to assess the design, using project profitability measures as the decision making tool in the economic model of polymer injection for 10 years at different polymer concentration 200, 500 and 1000 ppm, in addition to new five infill wells drilling scenario are given in Table 6.12.

| EOR technique | Water flooding | Infill well Drilling | Polymer flooding |
|---|------------------|----------------------|------------------|
| Duration of water flooding, years | 3 | 22 | 1 to 22 |
| Duration of polymer flooding, years | - | - | 10 |
| Additional capital expenditure, mm\$ | - | - | 8-11-18-31 |
| Polymer concentration, ppm | - | - | 200-500-1000 |
| Oil Price, \$/bbl | 30-50-80-115-150 | 30-50-80-115-150 | 30-50-80-115-150 |
| Incremental oil production cost, \$/bbl | - | 8-10-12 | 8-10-12 |
| Water injection cost, \$/bbl | - | 1-2-3 | 1-2-3 |
| Water production cost, \$/bbl | - | 1-2-3 | 1-2-3 |
| Polymer cost, \$/lb | - | - | 1-2-3-4 |
| Incremental polymer production cost, \$/bbl | - | - | 0-0.5-1 |
| Incremental polymer injection cost, \$/bbl | - | - | 0.25-0.5-1 |
| New infill well drilling (producer) | - | 3 | - |
| New infill well drilling (injector) | - | 2 | - |
| Well capital cost, mm\$/well | - | 24.5 | - |
| Well Operating cost, mm\$/yr | - | 2.45 | - |
| Additional capital expenditure, mm\$ | - | - | - |

Table 6.12 - Ranges used for economic parameters for the polymer injection of 10 years at polymer concentration 200, 500 and 1000 ppm, in addition to infill well drilling

6.7.3 Sensitivity and risk analysis for polymer flooding in addition to infill wells drilling

Three sensitivities have been run with polymer injected for 10 years at different polymer concentration 200, 500 and 1000 ppm, in addition to infill wells drilling scenario. The output results were fed in the economic mode where 14582 observations were calculated.

Figure 6.39 shows the relation between net present value and polymer concentration at oil prices of \$30, \$50, \$80, \$115 and \$150/bbl with economic parameters set as follows:; IOPC \$8/bbl; WIC \$1/bbl; WPC \$1/bbl; PC \$1/lb; IPPC \$0/bbl; IPIC \$0.25/bbl. The observations from the graph are:

1. At high oil price, as concentration increases NPV rises from 100 ppm to 500 ppm and then falls at polymer concentration of 1000 ppm.
2. Polymer concentration of 500 ppm is the optimal.
3. All the NPV values are positive.

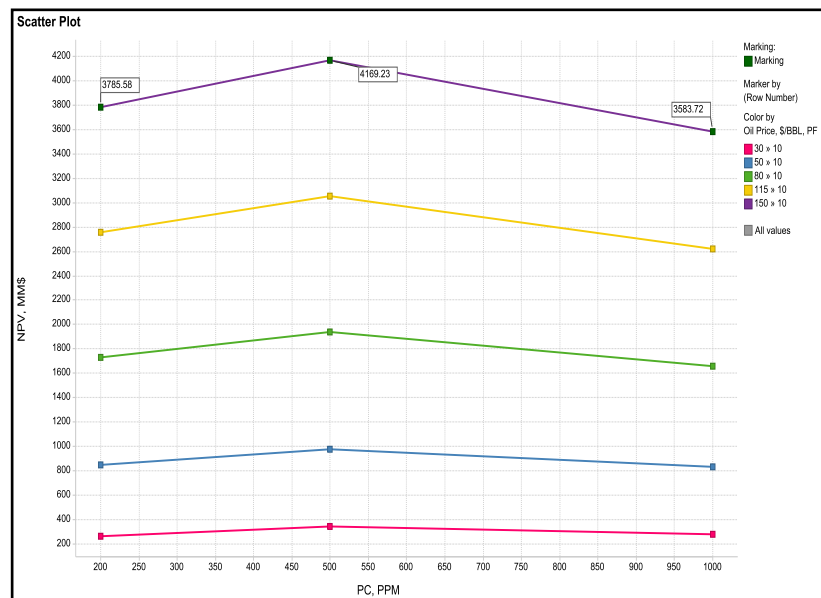


Figure 6.39 - Net present value vs. polymer concentrations at oil prices of \$30, \$50, \$80, \$115 and \$150/bbl. Each line is for a different oil prices and 10 years of polymer flooding

Figure 6.40 shows the relation between net present value and oil prices of \$30, \$50, \$80, \$115 and \$150/bbl at different polymer concentration and different water injection cost of at with economic parameters set as follows: PF 10 years; IOPC \$8/bbl; WIC \$1/bbl; WPC \$1/bbl; PC \$1/lb; IPPC \$0/bbl; IPIC \$0.25/bbl. The observations from the graph are:

1. At WIC: \$1/bbl,
 - a. The highest the NPV is with polymer concentration of 500 ppm at all oil prices.
 - b. At oil price of \$30/bbl, NPV from polymer concentration of 1000 ppm is slightly higher than the NPV from 200 ppm.
2. At WIC: \$2/bbl,
 - a. NPV with polymer concentration of 500 ppm is higher at all oil prices.
 - b. NPV with polymer concentration of 1000 ppm is higher than NPV with polymer concentration of 200 ppm at \$30/bbl oil price.
3. At WIC: \$2/bbl,
 - a. At oil price of \$30/bbl, NPV from polymer concentration of 1000 ppm is higher than the NPV from 200 and 500 ppm polymer concentration.
 - b. At oil price of \$30, \$50, and \$80/bbl, NPV from polymer concentration of 1000 ppm is higher than the NPV from 200 polymer concentration.

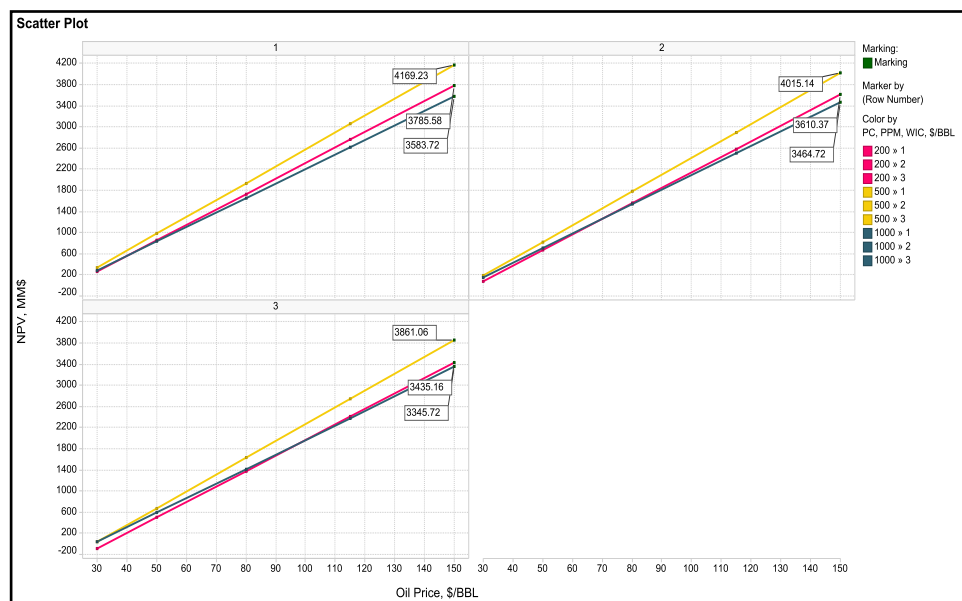


Figure 6.40 - Net present value vs. oil prices of \$30, \$50, \$80, \$115 and \$150/bbl at different polymer concentrations and different water injection cost at. Each line is for a different PC and different WIC and 10 years of polymer flooding

The results also are shown in more details in Table 6.13.

| PC, PPM | WIC, \$/BBL | Oil Prices \$/BBL | | | | |
|---------|-------------|-------------------|-----|------|------|------|
| | | 30 | 50 | 80 | 115 | 150 |
| 200 | 1 | 262 | 849 | 1730 | 2758 | 3786 |
| | 2 | 87 | 674 | 1555 | 2583 | 3610 |
| | 3 | -88 | 499 | 1380 | 2407 | 3435 |
| 500 | 1 | 341 | 979 | 1936 | 3053 | 4169 |
| | 2 | 187 | 825 | 1782 | 2899 | 4015 |
| | 3 | 33 | 671 | 1628 | 2745 | 3861 |
| 1000 | 1 | 280 | 830 | 1656 | 2620 | 3584 |
| | 2 | 161 | 711 | 1537 | 2501 | 3465 |
| | 3 | 42 | 592 | 1418 | 2382 | 3346 |

Table 6.13 – Average Net present value results at different polymer concentration (200,500, and 1000 ppm), oil prices (\$30, \$50, \$80, \$115 and \$150/bbl) and water injection cost (\$1, \$2 and \$3/bbl) based on 14582 observations

A total of 14582 economic calculations were performed, based on reservoir simulation output. Three sensitivities have been run with polymer injected for 10 years at different polymer concentration 200, 500 and 1000 ppm, in addition to infill wells drilling scenario (3 producers and 2 injectors) compared to only infill well drilling scenario, and the results are summarised below in Table 6.14:

1. The highest average NPV is at 500 ppm at all oil prices.
2. The probability of loss is 31 % at oil price \$30/bbl at 200 ppm polymer concentration, and zero probability of loss at oil prices \$50, \$80, \$115 and \$150/bbl.
3. The probability of loss is 11 % at oil price \$30/bbl at 500 ppm polymer concentration, and zero probability of loss at oil prices \$50, \$80, \$115 and \$150/bbl.
4. Zero probability of loss at 1000 ppm polymer concentration, and at all oil prices.

| Polymer Concentration, ppm | Statistics | Oil price \$/BBL | | | | |
|----------------------------|---------------------|------------------|-----|------|------|------|
| | | 30 | 50 | 80 | 115 | 150 |
| 200 | Avg. (NPV), mm\$ | 87 | 674 | 1555 | 2583 | 3610 |
| | Avg. (NPV), mm\$ | 175 | 175 | 175 | 175 | 175 |
| | Probability loss, % | 31 | 0.0 | 0.0 | 0.0 | 0.0 |
| 500 | Avg. (NPV), mm\$ | 187 | 825 | 1782 | 2899 | 4015 |
| | StdDev. (NPV) | 154 | 154 | 154 | 154 | 154 |
| | Probability loss, % | 11 | 0.0 | 0.0 | 0.0 | 0.0 |
| 1000 | Avg. (NPV), mm\$ | 161 | 711 | 1537 | 2501 | 3465 |
| | StdDev. (NPV) | 119 | 119 | 119 | 119 | 119 |
| | Probability loss, % | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

Table 6.14 - Statistical data for polymer flooding in additional to infill well drilling sensitivity scenario, based on 14582 calculations

6.8 Conclusion

This approach will be very useful to the industry in helping to make the appropriate choice of EOR vs. Infill Well Drilling, taking full account of reservoir engineering AND economic considerations TOGETHER.

This thesis only focuses in a comprehensive way on the economic aspect of an enhanced oil recovery techniques (polymer flooding) and infill well drilling. The polymer data that have been used in this work were extracted from (Sorbie, 2000) and the reservoir simulation sensitivities for the Schiehallion Field did not capture the full physics behaviour for polymer flooding such as the temperature, the shear thinning, the different polymer type, and it would be highly recommended that these parameters have to be evaluated perhaps by laboratory tests, as well as other parameters such as the viscosity versus concentration and adsorption behaviour, for which values from the literature were used. Field specific data should be used where available.

In this chapter the approach was applied to the Schiehallion Field to identify optimal economic performance. The same reservoir simulation procedure was implemented for infill well drilling and polymer flooding individually, and was then applied in the same field, but where polymer is injected in addition to an infill well drilling programme.

In conclusion, the best scenario in the Schiehallion Field is the scenario where the polymer is injected in addition to an infill well drilling programme. The highest average NPV is at polymer concentration of 500 ppm at all oil prices and also all the NPVs are positive at all oil prices. The probability of loss is 11 % at oil price of \$30/bbl at 500 ppm polymer concentration, and zero probability of loss at oil prices of \$50, \$80, \$115 and \$150/bbl.

CHAPTER 7: CONCLUSIONS, IMPEMNTATION AND RECOMMENDATIONS FOR FUTURE RESEARCH

7.1 Conclusions

The question this work has addressed is whether there is a better method than the conventional way to evaluate such choices as whether to drill new wells or carry out a polymer flood.

The technique proposed, developed and applied in this thesis involves running a wide range of reservoir simulation scenarios based on the given reservoir description (in this case using the Eclipse 100 software) to test possible recovery outcomes; all these outcomes then provide input data that is used in a probabilistic economic evaluation tool. The technique shows strong positive correlations between the outcomes of the reservoir simulation calculations such as recovery factors and water cuts, and the results of the economic calculations in the decision analysis tool. Due to the large number of combined reservoir engineering and economic scenarios, Monte Carlo Simulation and advanced analysis were developed, resulting in probability distributions of large data sets, visualised using the Spotfire software.

The methodology that is described in this thesis helps determine the economic viability of the various recovery options by plotting the net present value versus time to compare between polymer flooding and infill well drilling in the decision making tool, using a wide range of operational and economic parameters to help oil companies make the choose whether to do an EOR project or drill infill wells to maximise recovery. Critically, the choice is not being made based on a limited set of calculations (Say P10, P50 and P90) and then the result of these limited calculations being forward to the economic analysis, but on a full suite of reservoir engineering scenarios, with all results then informing the economic analysis, so a much more comprehensive distribution of possible outcomes is considered.

The method and the primary calculations of this work was initially applied to a synthetic scenario with constant economic parameters, which has demonstrated the impact that oil price can have on the decision making process.

With relatively early application of polymer flooding at a concentration of 1000 ppm, the method shows that in this case polymer flooding is clearly more economically attractive than infill well drilling. Specifically, in this scenario, even 1 year of polymer flooding at 1000 ppm gives a NPVI of 18.50 for an oil price of \$50, whereas one infill well only gives a NPVI of 5.20 at the same oil price.

The method was then applied and tested with varied operational and economic parameters to investigate the impact in delaying the start of polymer flooding to identify whether it is better to start polymer flooding earlier or later in the life of the project. Consideration was also given to the optimum polymer concentration, and the impact that factors such as oil price and polymer cost have on this decision.

The result of the infill well drilling option in the simple synthetic model showed no significant increase in oil recovery for all timing of drilling the new wells. Thus infill well drilling would never be a viable option in this specific scenario, and so no further economic evaluation was carried out for infill well drilling. This highlights that sometimes the outcome will become obvious for technical reasons, and thus the full economic analysis will not be required.

The technique was then applied to the Arbroath Field (North Sea) where the choice has already been made (infill well drilling), to test the robustness of the method against a conventional decision making process for which there is historical data.

Scenarios where the actual oil viscosity (0.4 cP) and where a heavy oil exists were compared. Fractional flow analysis identified that the increase in recovery due to polymer injection would be more significant in the heavy oil case.

This was confirmed by the economic analysis. For the original (low viscosity) oil, all scenarios showed that infill well drilling would be better economically, validating the choice made by the engineers. For similar setting but with a heavy oil, polymer flooding

would have a higher probability of success at high oil price ($< \$115/\text{bbl}$) only. Also there is limit to the amount of polymer that should be injected, the optimum being 500 ppm, with the duration of polymer injection dependent on the oil price.

The approach was then finally carried out for the Schiehallion Field, where the choice has yet to be made, a field which is currently under waterflood management, and where the operator is considering polymer flooding as an alternative (or in addition) to infill well drilling.

Water injection cost had a higher impact on NPV than other parameters such as water production cost and well operating cost in the infill well drilling scenario.

The impact of water injection cost on NPV for different polymer flooding periods was evaluated. Increasing the water injection cost from \$1 to \$3/bbl has a large impact on net present values at a low oil price of \$30/bbl. The NPVs are negative for polymer flooding periods of between 1 and 3 years at a water injection cost of \$1/bbl while the NPVs are negative for all scenarios at water injection cost of \$3/bbl. At high oil prices of \$150/bbl, increasing the water injection cost from \$1 to \$3/bbl decreases the NPVs to a lesser extent than was true at \$30/bbl. The NPVs are all positive for all polymer flooding periods of 1, 3, 5 and 10 years at water injection costs of between \$1 and \$3/bbl.

The analysis carried out using this method compares revenue generated from producing more oil (while is obviously higher at higher oil prices) with costs associated with drilling new wells, versus the cost of building and operating polymer injection facilities. This work does not consider any correlation there may be between well drilling costs, polymer costs and oil prices, but nonetheless the relationship between recovery method and the timing of expenditure (when is money is spent on drilling wells, purchasing polymer, etc.) and the timing of revenue (when is the most incremental oil produced) is identified as being very important.

Polymer flooding is shown to outperform infill well drilling when it has a lower maximum capital outlay (MCO). The higher the well cost the more the cost savings for

polymer flooding. Thus, whether greater emphasis is placed on NPV or MCO may significantly alter the decision.

Scenarios where polymer flooding was carried out in addition to infill well drilling were also considered.

To generalise these findings we conclude that when there is uncertainty about future oil prices – indeed, when would this not be the case? – an intermediate polymer concentration (Say 500 ppm) is going to be the preferable choice.

In general, short periods of polymer injection do not make best use of the upfront capital investment, and thus injecting polymer as early as possible and for as long as is best. The duration of the polymer flood is, however, subjected to optimization, and is very sensitive to the oil price.

As noted, the methodology does not consider correlations between economic parameters, which in general will exist. For example drilling costs and polymer costs will tend to increase as the oil price increases. Also the model does not include royalty and taxes, which will be dependent on the fiscal setting.

The other primary limitation of this work is that in the various applications not all engineering parameters and sensitivities have been evaluated. For the infill well scenarios, much more work would need to be carried out to locate optimal locations and scheduling for new well drilling. Also more detailed modelling of the polymer flooding should be carried out, using laboratory data for the specific field in question, such as viscosity – shear relationships, adsorption isotherms, inaccessible pore volume, temperature dependences, etc.

In all cases (polymer or infill well) there will be sensitivity to the underlying geological model. Clearly, by the times these types of decision are being made, a history matched model should be available. However, the target unrecovered oil will be in locations where, by definition, no wells have yet been drilled, and so geological data definition will be poorer. Therefore, it will be important to consider uncertainty in the geological models as part of the work flow.

7.2 Recommendations for implementation

This method has been developed to analyse polymer flooding specifically. However as noted in chapter 2, various other non-thermal EOR techniques will have similar inputs, and as this method will be suitable for analysis there also will be some minor modifications.

Therefore, when an asset team is reviewing future recovery methods, they should first consider various technical issues which may affected the choice (e.g. does reservoir temperature make polymer flooding impossible), and perform fractional flow analysis, as a part of pre-screening process. Once this has been done, data should be gathered to use as input for this methodology – such as reservoir simulation models, laboratory data, economic inputs, and the process can then be initiated. Subsequent changes to the economic inputs (say a better constraint on polymer prices) can then lead to the economic calculations being repeated. Clearly running reservoir simulation calculation again will be more time consuming.

It should be noted, that in all scenarios for the Schiehallion study, polymer flooding accompanied by an infill well drilling programme was preferable to just polymer flooding on its own, or just infill well drilling on its own. Therefore, combination of option, such as new well drilling and EOR, or polymer and low salinity flooding, should be considered using this method.

Future work should consider in more detail optimisation of scenarios where polymer injection is carried out in conjunction with new well drilling. Polymer injection necessarily involves a decrease in injectivity, and it must be remembered that as well as sweep efficiency gains from polymer flooding, reservoir pressure must also be maintained.

A detailed study would consider many possible locations for infill well engineers would consider geological model, any 4D seismic data that is available and reservoir simulation calculation of bypassed oil.

The methodology should be applied to other enhanced oil recovery techniques such as Brightwater™ injection, miscible gas flooding, CO₂ - EOR, etc.

Polymer flooding should be implemented into a pilot well first before making any final judgment as to whether polymer flooding is economically feasible or not. The cost of undertaken the pilot test should be included in the economic analysis.

An economic evaluation should be made as to at what point to stop polymer flooding (This work here concentrated on when to start polymer flooding).

Field specific laboratory data should be used in any field specific study.

There will be a correlation between polymer cost and oil price. Well cost and other parameters will also be dependent an oil price and in future these correlations should be included in the economic analysis.

7.3 Recommendations for future research

Future research could look at developing this method to consider other EOR scenarios where the economic and the reservoir modelling would be much more complex. For example, during CO₂-EOR, the price of carbon would have to be included in the analysis. This is not just a matter of adding another cost (or in the case of carbon, another source of revenue or avoidance of tax), but also an understanding of the balance between oil price and carbon price that will enable CO₂-EOR to be a viable competitor to other EOR methods. A driver in this scenario would not just be maximising oil recovery, and revenue from oil recovery, but also creating environmental improvements by injecting as much CO₂ as possible. There will be a price of CO₂ and a price of oil at which injecting more CO₂ for environmental reasons will be financially beneficial, even if it reduces the amount of oil that is produced.

Appendix A1 - Synthetic model (oil/water/polymer)

RUNSPEC

TITLE

DIMENS

30 21 15 /

OIL

WATER

POLYMER

FIELD

WELLDIMS

2 20 1 2 /

START

1 'JAN' 2009 /

NSTACK

100 /

UNIFOUT

GRID =====

INIT

BOX

1 30 1 21 1 1 /

TOPS

630*4000/

EQUALS

'DX' 75 1 30 1 21 1 15/

'DY' 75/

'DZ' 10/

'PERMX' 100 1 30 1 21 1 5/

'PORO' 0.2 /

'PERMX' 1000 1 30 1 21 6 10/

'PORO' 0.22 /

'PERMX' 100 1 30 1 21 11 15/

'PORO' 0.2 /

/

COPY

PERMX PERMY /

PERMX PERMZ /

/

MULTIPLY

PERMZ 0.1 /

/

PROPS =====

SWOF

0.2016 0.0000 0.9656 0.2469

0.2527 0.0006 0.7221 0.1583

| | | | |
|--------|--------|--------|--------|
| 0.3038 | 0.0051 | 0.5264 | 0.0963 |
| 0.3550 | 0.0173 | 0.3697 | 0.0548 |
| 0.4061 | 0.0411 | 0.2477 | 0.0286 |
| 0.4573 | 0.0802 | 0.1560 | 0.0133 |
| 0.5084 | 0.1386 | 0.0903 | 0.0052 |
| 0.5595 | 0.2202 | 0.0462 | 0.0015 |
| 0.6107 | 0.3286 | 0.0195 | 0.0003 |
| 0.6618 | 0.4679 | 0.0058 | 0.0000 |
| 0.7129 | 0.6418 | 0.0007 | 0.0000 |
| 0.7641 | 0.8543 | 0.0000 | 0.0000 |
| 1.0000 | 1.0000 | 0.0000 | 0.0000 |

/

-- Densities in lb/ft

| | | | |
|----|-----|-----|-----|
| -- | Oil | Wat | Gas |
|----|-----|-----|-----|

| | | | |
|----|-----|-----|-----|
| -- | --- | --- | --- |
|----|-----|-----|-----|

DENSITY

| | | |
|----|----|--------|
| 49 | 63 | 0.01 / |
|----|----|--------|

-- PVT data for dead oil

| | | | |
|----|---|----|-----|
| -- | P | Bo | Vis |
|----|---|----|-----|

| | | | |
|----|------|------|-------|
| -- | ---- | ---- | ----- |
|----|------|------|-------|

PVDO

| | | |
|-----|------|-----|
| 300 | 1.25 | 1.0 |
|-----|------|-----|

800 1.20 1.1

6000 1.15 2.0 /

-- PVT data for water

-- P Bw Cw Vis Viscosity

-- ----

PVTW

4500 1.02 3e-06 0.8 0.0 /

-- Rock compressibility

-- P Cr

-- ----

ROCK

4500 4e-06 /

PLYVISC

0.0 1.0

70.0 10.0 /

PLYROCK

0.16 1.5 1000.0 1 0.005 /

PLYADS

0.0 0.005

20.0 0.010

70.0 0.010 /

TLMIXPAR

1.0 /

PLYMAX

50.0 0.0 /

RPTPROPS

-- PROPS Reporting Options

--

'PLYVISC'

/

--RPTREGS

-- Controls on output from regions section

--

--'MISCNUM'

--/

SOLUTION =====

EQUIL

4000 4000 6000 0 0 0 0 0 0 /

RPTRST

BASIC=2/

--RPTSOL

-- Initialisation Print Output

--

--'RESTART=2' 'FIP=2' 'PBLK' 'SALT' 'PLYADS' 'RK' 'FIPPLY=2' /

SUMMARY =====

-- Field average pressure

FPR

-- Bottomhole pressure of all wells

WBHP

/

-- Field Oil Production Rate

FOPR

-- Field Water Production Rate

FWPR

-- Field Oil Production Total

FOPT

-- Field Water Production Total

FWPT

-- Field Water cut

FWCT

-- Field Water injection total

FWIT

-- Field oil recovery efficiency

FOE

--Well Polymer production rate

WCPR

```
'P' /

--Well Polymer production total

WCPT

'P' /

--Well Polymer injection rate

WCIR

'I' /

--Well Polymer Injection total

WCIT

'I' /

EXCEL

SCHEDULE =====

--RPTSCHED

--'PRES' 'SWAT' 'RESTART=2' 'FIP=2' 'WELLS=2' 'SUMMARY=2' 'CPU=2' 'WELSPECS'

--'NEWTON=2' 'PBLK' 'SALT' 'PLYADS' 'RK' 'FIPSALT=2' /

WELSPECS

'I' 'G' 8 11 4000 'WAT' 0.0 'STD' 'SHUT' 'NO' /

'P' 'G' 22 11 4000 'OIL' 0.0 'STD' 'SHUT' 'NO' /

/

COMPDAT

'I' 8 11 1 15 'OPEN' 0 .0 1.0 /

'P' 22 11 1 15 'OPEN' 0 .0 1.0 /

/

WCONPROD
```

'P' 'OPEN' 'BHP' 5* 3500.0 /

/

WECON

'P' 1* 1* 0.9 2* WELL YES /

/

WCONINJE

'I' 'WAT' 'OPEN' 'RATE' 2000.0 /

/

WPOLYMER

'I' 0.0 0.0 /

/

TUNING

1* 185 /

/

2* 100 /

DATES

1 APR 2009/

1 JUL 2009/

1 OCT 2009/

1 JAN 2010/

1 APR 2010/

1 JUN 2010/

1 JUL 2010/

1 JAN 2011/

/

WPOLYMER

'I' 500.0 0.0 /

/

DATES

1 JAN 2012/

1 JAN 2013/

1 JAN 2014/

1 JAN 2015/

1 JAN 2016/

1 JAN 2017/

1 JAN 2018/

1 JAN 2019/

1 JAN 2020/

1 JAN 2021/

/

WPOLYMER

'I' 0.0 0.0 /

/

DATES

1 JAN 2022/

1 JAN 2023/

1 JAN 2024/

1 JAN 2025/

1 JAN 2026/

1 JAN 2027/

1 JAN 2028/

1 JUL 2028/

1 JAN 2029/

1 JUL 2029/

1 JAN 2030/

1 JUL 2030/

1 JAN 2031/

1 JUL 2031/

1 JAN 2032/

1 JUL 2032/

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1 JAN 2047/

1 JUL 2047/

1 JAN 2048/

1 JUL 2048/

1 JAN 2049/

1 JUL 2049/

1 JAN 2050/

1 JUL 2050/

/

--RPTSCHED

--'PRES' 'SWAT' 'RESTART=2' 'FIP=2' 'WELLS=2' 'SUMMARY=2' 'CPU=2' 'NEWTON=2'

--'PBLK' 'SALT' 'PLYADS' 'RK' 'FIPSALT=2' /

END

Appendix A2 - Arbroath model (oil/water/polymer)

*****NEW RUNSPEC SECTION*****

RUNSPEC

TITLE

ARBROATH 1996 MODEL STUDY

--nosim

DIMENS

52 62 13 /

OIL

WATER

POLYMER

GAS

DISGAS

FIELD

EQLDIMS

1 100 2 1 20 /

EQLOPTS

'IRREVERS' /

TABDIMS

18 1 15 20 13 20 /

REGDIMS

13 1 0 0 0 1 /

WELLDIMS

40 16 5 10 /

LGR

0 0 0 0 0 10 'NOINTERP' /

VFPPDIMS

9 5 4 1 2 50 /

VFPIDIMS

9 5 50 /

AQUDIMS

22 22 1 0 100 62 /

SMRYDIMS

3000 /

START

1 'APR' 1990 /

NSTACK

100 /

UNIFOUT

UNIFIN

TRACERS

0 4 /

-- Data check run

--NOSIM

--*****END OF NEW RUNSPEC SECTION*****

-- save data for fast restart

save

/

grid

init

-- (p) mess com warn prob error bug (s) mess com warn prob error bug

messages

1* 1* 1* 1* 1* 1* 1* 1* 1* 1* 1* 1*

/

noecho

-- top forties map from Shiraz Dhanani (Variable Vok method, 3-D seismic)

-- Abandonment feature added to create top sand map

-- Corner point geometry used

newtran

include

'arbgrid/ARB1_TOPS.GRDECL' /

include

'arbgrid/ARB_NTG.GRDECL' /

include

'arbgrid/ARB_PORO.GRDECL' /

-- perm derived from the following transform

--Insitu Perm = (Apparent Core Perm) **0.8 Based on best fit PTA to log derived

-- and hand contoured to fit well test results

-- $k_z = k_x * 0.1 * NTG^{**2}$

-- Multz = 1.0, 0.1 or 0.01 depending on shale separation, and adjusted during H

include

'arbgrid/ARB_PERMX.GRDECL' /

include

'arbgrid/ARB_PERMZ.GRDECL' /

include

'arbgrid/ARB_MULTZ.GRDECL' /

--

--rptgrid

--23*0 1 /

echo

multiply

-- T1 Area

'permx' 1.2 20 22 36 38 5 7 /

-- T17 Area

--Increase perm in L1-3 in T17 area

'permx' 4 36 38 33 39 1 3 /--CHANGE OD

-- T19 Area

--Increase perm in L5-7,North of T19

'permx' 5.1 13 17 1 16 4 5 /--CHANGE_ARB04C

-- T10-T12 Area

--Increase perm in L1-5 between T12 and T10

'permx' 5 17 18 26 31 1 5 / --CHANGE_ARB04B

--Decrease perm in L3 between T12 and T10

'permx' 0.1 17 18 26 31 3 3 / --CHANGE_ARB04C

-- T4 Area

--Increase perm in L1-5,South of T4

'permx' 4.0 18 25 42 62 1 5 / --CHANGE OD

-- T3 Block

--Increase perm in L2-3, in T3-T11z Block

'permx' 4 32 33 45 49 2 3 / --CHANGE OD

-- T13 Block

--Increase perm in L2 East of T13

'permx' 2.0 37 45 44 47 4 5 / --CHANGE OD

--Decrease perm in L2 South of T13

'permx' 2.0 35 37 46 50 2 3 / --NEW CHANGE(was 2.0)

-- T20 Block

--Increase perm in L3-4,North of T20

'permx' 2.0 25 32 8 19 4 4 /--CHANGE 99ARB06_TR

'permx' 1.67 27 29 18 20 3 3 / --Extra perm increase around well only

'permx' 0.83 27 29 18 20 1 2 / --Extra perm increase around well only

-- T2 Area

--Increase perm in L4-5,at T2

'permx' 0.4 29 33 31 35 3 3 / --CHANGE multiply permx *0.4 (was 0.5)

'permx' 1.0 29 33 31 35 4 4 / --CHANGE multiply permx *0.4 (was 0.5)

'permx' 0.57 29 33 31 35 5 5 / --CHANGE multiply permx *0.4 (was 0.5)

-- T15 Block

--Decrease perm North of T15 L1-4

'permx' 0.35 40 52 1 16 1 4 /--CHANGE OD

-- T5 Area

--Increase Perm in area around T5

'permx' 3.5 39 43 24 30 5 8 / -- CHANGE

/

copy

'permx' 'permy' 1 52 1 62 1 13 /

/

PINCH

2.0 'GAP' 10. /

MINPV

5000. /

--rptgrid

-- dx dy dz kx ky kz mx y z po ntg top pv md tx ty tz - - aqcon

-- 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 -- 22

--3*0 1 8*0 1 /

equals

--MAPPED BARRIERS

--BARRIER 1

--T19 channel - Western side

'multx' 0.1 11 11 1 6 1 5 /

'multy' 0.1 12 12 6 6 1 5 /

'multx' 0.1 12 12 7 18 1 5 / --T19 at Y=15

'multx' 0.2 12 12 19 21 1 5 / --T14 at Y=21

'multy' 0.1 11 12 21 21 1 5 /

'multx' 0.1 10 10 22 22 1 5 /

'multy' 0.1 8 10 22 22 1 5 /

'multx' 0.1 7 7 23 23 1 5 /

'multy' 0.1 4 7 23 23 1 5 /

'multx' 0.1 4 4 24 24 1 5 /

'multy' 0.1 4 4 24 24 1 5 /

'multx' 0.1 3 3 25 26 1 5 / --P50

'multy' 0.1 3 3 26 26 1 5 / --P50

'multx' 0.1 2 2 27 32 1 5 / --P50

'multy' 0.1 2 2 32 32 1 5 / --P50

'multx' 0.1 1 1 33 36 1 5 / --P50

--BARRIER 2

--T19 channel - Eastern side

'multx' 0.01 15 15 1 4 1 13 /

'multy' 0.01 16 16 4 4 1 13 /

'multx' 0.01 16 16 5 8 1 13 /

'multy' 0.01 17 17 8 8 1 13 / --P10

'multx' 0.01 17 17 9 9 1 13 / --P10

'multy' 0.01 18 19 9 9 1 13 / --P10

'multx' 0.01 19 19 10 10 1 13 / --P10

'multy' 0.01 20 20 10 10 1 13 / --P10

'multx' 0.01 20 20 11 14 1 13 / --P10

'multy' 0.01 19 21 14 14 1 13 / --P50

'multx' 0.01 21 21 15 17 1 13 / --T19 at Y=15 (long way)

'multy' 0.01 20 21 17 17 1 13 / --P50

'multx' 0.01 19 19 18 18 1 13 / --P10

'multy' 0.01 19 19 18 18 1 13 / --P10

'multx' 0.01 18 18 19 19 1 13 / --P75

'multy' 0.01 18 18 19 19 1 13 /

'multx' 0.01 17 17 20 20 1 13 /

'multy' 0.01 17 17 20 20 1 13 /

'multx' 1.0 16 16 21 23 1 13 / --T14 at Y=21

'multy' 1.0 17 17 23 23 1 13 /

```

'multx' 1.0  17 17 24 25 1 13 /
'multy' 1.0  18 20 25 25 1 13 /
'multx' 1.0  20 20 26 27 1 13 / --T6 at Y=26 --P10
'multy' 1.0  20 20 27 27 1 13 /    --P10
'multx' 0.01 19 19 28 30 1 13 /
'multy' 0.01 20 20 30 30 1 13 /
'multx' 0.01 20 20 31 33 1 13 / --T12 Area at Y=32 --P10 - P50
'multy' 0.01 21 21 33 33 1 13 /
'multx' 0.01 21 21 34 34 1 13 /
'multy' 0.01 22 24 34 34 1 13 /    --P50

-----

--BARRIER 3

--T20 Channel - Western side

-- 'multy' 0.1  21 21 10 10 1 13 / --P10
-- 'multx' 0.1  21 21 11 11 1 13 / --P10
-- 'multy' 0.1  22 24 11 11 1 13 / --P10
-- 'multx' 0.1  24 24 12 19 1 13 / --T20 at Y=19  --P10
-- 'multy' 0.1  22 24 19 19 1 13 / --P50
-- 'multx' 0.1  24 24 20 27 1 13 / --T16 at Y=25, T6 at Y=26 --P50 - P10
'multy' 0.1  25 26 27 27 1 13 / --P50
'multx' 0.1  26 26 28 30 1 13 / --P50
'multy' 0.1  26 26 30 30 1 13 / --P50
'multx' 0.1  25 25 31 31 1 13 / --P50
'multy' 0.1  25 25 31 31 1 13 / --P50
'multx' 0.2  24 24 32 36 1 5 / --P50 Extended down to Barrier 7

-----

--BARRIER 4

--T10-T12 Channel - Western side

```

```
-- 'multy' 0.1  9 14 24 24 1 13 / --P75
-- 'multx' 0.1  14 14 25 25 1 13 /
-- 'multy' 0.1  15 15 25 25 1 13 /
-- 'multx' 0.1  15 15 26 26 1 13 /
-- 'multy' 0.1  16 16 26 26 1 13 /
-- 'multx' 0.1  16 16 27 33 1 13 / --T10 at Y=27, T12 at Y=32
-- 'multy' 0.1  6 16 33 33 1 13 / --P75
```

--BARRIER 4A

--Alternative T10-T12 Channel - Western side

```
'multy' 0.01  9 15 27 27 1 5 / --P75
'multx' 0.01  15 15 28 29 1 5 / --T10 at Y=27, T12 at Y=32
'multy' 0.01  16 16 29 29 1 5 / --P75
'multx' 0.01  16 16 30 33 1 5 /
'multy' 0.01  6 16 33 33 1 5 /
'multx' 0.01  16 16 34 35 1 5 / --Link up to Barrier 5
```

--Link up to fault No 1

```
-- 'multx' 0.01  10 10 23 24 1 5 /
-- 'multy' 0.01  11 12 24 24 1 5 / --P75
-- 'multx' 0.01  12 12 25 27 1 5 /
```

--BARRIER 5

--T1-T4 Channel - Western side

```
'multy' 0.1  5 17 35 35 1 13 / --P75
'multx' 0.1  17 17 36 37 1 5 / --T1 at Y=37
'multy' 0.1  18 18 37 37 1 5 /
'multx' 0.1  18 18 38 41 1 5 /
'multy' 0.05  19 20 41 41 1 5 /
```

```

'multx' 0.05  20 20 42 46 1 5 / --T4 at Y=44

'multy' 0.05  20 20 46 46 1 5 / --P75

'multx' 0.1   19 19 47 50 1 5 / --P10

-- 'multx' 0.1  19 19 51 54 1 13 / --P10

-----

--BARRIER 6

--Hole near T2

-- 'multx' 0.1  28 28 33 35 1 13 / --P50

-- 'multy' 0.1  29 30 32 32 1 13 / --P50

-- 'multx' 0.1  30 30 33 35 1 13 / --P50

-----

--BARRIER 7

--Hole near T1

'multy' 0.2   24 25 40 40 1 5 / --P50

'multx' 0.2   23 23 37 40 1 5 / --P50

'multy' 0.2   24 28 36 36 1 5 / --P50 to P10

'multx' 0.2   28 28 37 40 1 5 / --P10

'multy' 0.2   28 28 40 40 1 5 / --P10

-----

--BARRIER 8

--Major Crescent Shape Slump south of T7

'multx' 0.01  15 15 62 62 1 5 / --P75

'multy' 0.01  16 17 61 61 1 5 /

'multx' 0.01  17 17 61 61 1 5 /

'multy' 0.01  18 19 60 60 1 5 /

'multx' 0.01  19 19 60 60 1 5 /

'multy' 0.01  20 21 59 59 1 5 /

'multx' 0.01  21 21 59 59 1 5 /

```

```

'multy' 0.01 22 22 58 58 1 5 /
'multx' 0.01 22 22 57 58 1 5 /
'multy' 0.01 23 24 56 56 1 5 /
'multx' 0.01 24 24 56 56 1 5 /
'multy' 0.01 25 25 55 55 1 5 /
'multx' 0.01 25 25 55 55 1 5 /
'multy' 0.01 26 29 54 54 1 5 / --T7 at X=26
'multx' 0.01 29 29 55 55 1 5 /
'multy' 0.01 30 30 55 55 1 5 /
'multx' 0.01 30 30 56 62 1 5 / --P75
'multy' 0.01 31 33 55 55 1 5 / --LINK BETWEEN fault 8 and fault 11

-----

--BARRIER 9

--Crescent Shape Slump south of T18

-- 'multx' 0.1 13 13 61 61 1 13 / --P50
-- 'multy' 0.1 14 15 60 60 1 13 / --P50
-- 'multx' 0.1 15 15 60 60 1 13 / --P50
-- 'multy' 0.1 16 17 59 59 1 13 / --P50
-- 'multx' 0.1 17 17 59 59 1 13 / --P50
-- 'multy' 0.1 18 19 58 58 1 13 / --P50
-- 'multx' 0.1 19 19 58 58 1 13 / --P75
-- 'multy' 0.1 20 21 57 57 1 13 / --
-- 'multx' 0.1 21 21 57 57 1 13 /
-- 'multy' 0.1 22 22 56 56 1 13 /
-- 'multx' 0.1 22 22 56 56 1 13 /
-- 'multy' 0.1 23 23 55 55 1 13 /
-- 'multx' 0.1 23 23 54 55 1 13 /
-- 'multy' 0.1 24 24 53 53 1 13 /

```

```

-- 'multx' 0.1  24 24 53 53 1 13 /
-- 'multy' 0.1  25 25 52 52 1 13 /
-- 'multx' 0.1  25 25 52 52 1 13 /
-- 'multy' 0.1  26 26 51 51 1 13 /
-- 'multx' 0.1  26 26 51 51 1 13 /
-- 'multy' 1.0  27 27 50 50 1 13 / --Gap at T18, X=27
-- 'multy' 0.1  28 32 50 50 1 13 / --P50

-----

--BARRIER 10

--Major Cross Feature North of T18

--CHANGE multiplier to 0.01 from 0.1

  'multx' 0.05  24 24 41 44 1 5 / --Extension to barrier 7

  'multx' 0.05  24 24 45 45 1 5 / --nr T4 --P50

  'multy' 0.05  25 25 45 45 1 5 / --P50

  'multx' 0.05  25 25 46 46 1 5 / --P50

  'multy' 0.05  26 26 46 46 1 5 / --P50

--  'multx' 0.05  26 26 47 47 1 5 / --CHANGE barrier extended south
--  'multy' 0.05  27 27 47 47 1 5 / --CHANGE barrier extended south
--  'multx' 0.1  27 27 48 48 1 5 / --P50
--  'multy' 0.1  27 30 47 47 1 13 / --P50
--  'multx' 0.1  30 30 44 47 1 13 / --N-S between T3 and T4 --P10
--  'multx' 0.1  30 30 48 48 1 13 / --P50
--  'multy' 0.1  31 33 48 48 1 13 / --P50
--  'multx' 0.1  33 33 47 48 1 13 / --N-S between T3 and T13 --P50
--  'multy' 0.1  34 34 46 46 1 13 / --P50
--  'multx' 0.1  34 34 44 46 1 13 / --P50

-----

--BARRIER 11

```


--Crescent Slump South of T11

'multx' 0.01 35 35 60 62 1 5 / --All P50

'multy' 0.01 35 35 59 59 1 5 /

'multx' 0.01 34 34 58 59 1 5 /

'multy' 0.01 34 34 57 57 1 5 /

'multx' 0.01 33 33 56 57 1 5 /

'multy' 0.01 34 35 55 55 1 5 /

'multx' 0.01 35 35 55 55 1 5 /

'multy' 0.01 36 37 54 54 1 5 / --T11 at X=37

'multx' 0.01 37 37 55 60 1 5 /

'multy' 0.01 38 38 60 60 1 5 /

'multx' 0.01 38 38 61 62 1 5 / --P50

--BARRIER 12

--T11 to S.E Aquifer

'multx' 0.03 35 35 50 54 1 13 / -- 1st Fault

'multy' 0.03 36 38 49 49 1 13 / --1st Fault

'multx' 0.01 37 37 52 54 1 13 / --T11 at Y=53 --All P50

'multy' 0.01 37 37 51 51 1 5 /

'multx' 0.01 37 37 51 51 1 5 /

'multy' 0.01 38 38 50 50 1 5 /

'multx' 0.01 38 38 50 50 1 5 /

'multy' 0.01 39 39 49 49 1 5 /

'multx' 0.01 39 39 49 49 1 5 /

'multy' 0.01 40 40 48 48 1 5 /

'multx' 0.01 40 40 48 48 1 5 /

'multy' 0.01 41 41 47 47 1 5 /

'multx' 0.01 41 41 47 47 1 5 /

```

'multy' 0.01 42 44 46 46 1 5 /
'multx' 0.01 44 44 46 46 1 5 /
'multy' 0.01 45 45 45 45 1 5 /
'multx' 0.01 45 45 45 45 1 5 /
'multy' 0.01 46 46 44 44 1 5 /
'multx' 0.01 46 46 44 44 1 5 /
'multy' 0.01 47 49 43 43 1 5 / --P50

-----

--BARRIER 13

--East of T5-T17-T8-T13

-- 'multx' 0.1 42 42 26 26 1 13 / --P75
-- 'multy' 0.1 42 42 26 26 1 13 / --P75
-- 'multx' 0.1 41 41 27 28 1 13 / --T5 at Y=27
-- 'multy' 0.1 41 41 28 28 1 13 / --P75
-- 'multx' 0.1 40 40 29 29 1 13 / --P75
-- 'multy' 0.1 40 40 29 29 1 13 / --P75
-- 'multx' 0.1 39 39 30 31 1 13 / --P75
-- 'multy' 0.1 39 39 31 31 1 13 / --P75
-- 'multx' 0.1 38 38 32 32 1 13 / --T17 at Y=32
-- 'multy' 0.1 38 38 32 32 1 13 / --P75
-- 'multx' 0.1 37 37 33 34 1 13 / --P75
-- 'multy' 0.1 37 37 34 34 1 13 / --P75
-- 'multx' 0.1 36 36 35 41 1 3 / --T8 at Y=36 --P10
-- 'multy' 0.1 37 37 41 41 1 3 /
-- 'multx' 0.1 37 37 42 46 1 3 / --T13 at Y=45 --P50
-- 'multy' 0.1 38 38 46 46 1 3 / --P50
-- 'multx' 0.1 38 38 47 49 1 3 / --P50

-----

```

--BARRIER 14

--Channel edge West of T15, T5, T17

'multx' 0.1 39 39 13 22 1 13 / --T15 at Y=19, but another fault before the

'multy' 0.1 39 39 22 22 1 13 / --P75

'multx' 0.1 38 38 23 24 1 13 /

'multy' 0.1 38 38 24 24 1 13 /

'multx' 0.1 37 37 25 26 1 13 /

'multy' 0.1 37 37 26 26 1 13 /

'multx' 0.1 36 36 27 27 1 13 / --T5 at Y=27 --P75

-- 'multy' 0.1 36 36 27 27 1 13 / --P50

-- 'multx' 0.1 35 35 28 29 1 13 / --P50

-- 'multy' 0.1 35 35 29 29 1 13 / --P50

-- 'multx' 0.1 34 34 30 30 1 13 / --P50

-- 'multy' 0.1 33 34 30 30 1 13 / --P50

--BARRIER 15

--Channel edge East of T16,

-- 'multx' 0.1 32 32 26 30 1 13 / --P75 to P50

'multy' 0.1 33 33 10 23 1 13 / --P75

-- 'multx' 0.1 33 33 21 25 1 13 / --T16 at Y=25 --P75

-- 'multy' 0.1 34 34 20 20 1 13 / --P10

-- 'multx' 0.1 34 34 18 20 1 13 / --P10

--BARRIER 16

--Small barrier west of T15

-- 'multx' 0.1 42 42 16 16 1 13 / --All P50

-- 'multy' 0.1 42 42 16 16 1 13 /

-- 'multx' 0.1 41 41 17 18 1 13 /

```

-- 'multy' 0.1  41 41 18 18 1 13 /
-- 'multx' 0.1  40 40 19 21 1 13 / --T15 at Y=19
-- 'multy' 0.1  40 40 21 21 1 13 /

-----

--BARRIER 17

--Barrier between T5 and T9

'multx' 0.1  50 50 13 15 1 13 / --ALL P75
'multy' 0.1  50 50 15 15 1 13 /
'multx' 0.1  49 49 16 17 1 13 /
'multy' 0.1  49 49 17 17 1 13 /
'multx' 0.1  48 48 18 18 1 13 /
'multy' 0.1  48 48 18 18 1 13 /
'multx' 0.1  47 47 19 19 1 13 /
'multy' 0.1  47 47 19 19 1 13 /
'multx' 0.1  46 46 20 21 1 13 /
'multy' 0.1  46 46 21 21 1 13 /
'multx' 0.1  45 45 22 23 1 13 /
'multy' 0.1  45 45 23 23 1 13 /
'multx' 0.1  44 44 24 26 1 13 / --T9 at Y=25
'multy' 0.1  44 44 26 26 1 13 /
'multx' 0.1  43 43 27 32 1 13 / --CHANGE 0.1 to 0.00 for t17 wctchangback
'multy' 0.1  43 43 32 32 1 13 / --CHANGE 0.1 to 0.00 for t17 wctchangback
'multx' 0.1  42 42 33 36 1 13 / --CHANGE 0.1 to 0.00 for t17 wctchangback

-----

--BARRIER 18

--Barrier to West Channel of Montrose

'multx' 0.01  48 48 1 2 1 13 / --ALL P75
'multy' 0.01  48 48 2 2 1 13 /

```

'multx' 0.01 47 47 3 7 1 13 /

'multy' 0.01 47 47 7 7 1 13 /

'multx' 0.01 46 46 8 10 1 13 /

'multy' 0.01 46 46 10 10 1 13 /

'multx' 0.01 45 45 11 11 1 13 /

'multy' 0.01 45 45 11 11 1 13 /

'multx' 0.01 44 44 12 12 1 13 /

--BARRIER 19

--Slump Cross Feature to South of Montrose

'multy' 0.01 50 51 16 16 1 13 / --ALL P75

'multx' 0.01 51 51 17 18 1 13 /

'multy' 0.01 52 52 18 18 1 13 /

--BARRIER 20

--Circular Slump to East of T9

-- 'multx' 0.1 48 48 23 25 1 13 / --T9 at Y=25 --P75

-- 'multy' 0.1 48 48 25 25 1 13 /

-- 'multx' 0.1 47 47 26 31 1 13 /

-- 'multy' 0.1 48 50 31 31 1 13 /

-- 'multx' 0.1 50 50 31 31 1 13 /

-- 'multy' 0.1 51 51 30 30 1 13 /

-- 'multx' 0.1 51 51 23 30 1 13 / --P75

-- 'multy' 0.1 49 51 22 22 1 13 / --P50

--BARRIER 21

--Barrier between T10 and T12

-- 'multy' 0.1 15 19 30 30 1 13 /

--BARRIER 22

--Barrier between T11z and T07

'multx' 0.1 30 30 44 55 1 5 /

-- 'multx' 0.1 30 30 41 43 1 5 / --Extension to barrier 7

-- 'multy' 0.1 29 30 40 40 1 5 / --Extension to barrier 7

--Barriers to make T5 cone water

'multx' 0.01 40 40 26 27 5 8 /

'multx' 0.01 41 41 26 27 3 8 /

--T15 Test X-Fault

-- 'multy' 0.01 37 46 20 20 1 5 /

--Barrier between T11z and T13 --Links up with 1st barrier 12

'multy' 0.1 35 35 49 49 1 5 /

'multx' 0.1 34 34 45 49 1 5 /

/

multiply

-- T10 Block

--Decrease Multz between Layers 3 and 6 in T10

'multz' 0.1 16 16 27 27 3 6 /--CHANGE OD

-- T13 Block

--Increase Vertical Movement in L4-5 East of T13

'multz' 4.5 37 45 44 47 4 5 /--CHANGE OD

-- T14 Area

--Increase Communication between L2 and 3 between T12 and T10

'multz' 3 16 19 27 32 1 2 / --CHANGE OD

-- T4 Area

--Increase T4 Multz in L4 and 5

'multz' 8.0 22 24 43 45 5 6 / --CHANGE OD

-- T3 Area

--Increase/Reduce Vertical Movement in T3 and nearby area

'multz' 20. 31 33 43 45 5 5 /

'multz' 2. 31 33 43 45 6 6 /

'multz' 10. 31 33 43 45 10 10 /

'multz' 0.1 30 34 42 46 7 7 /

-- T5 Area --CHANGE

--Increase Kv in area around T5

'multz' 3.5 39 43 24 30 5 8 / -- CHANGE

-- T15 Area

--Increase Pressure Communication to North of T15

'multz' 5 42 42 19 19 4 5 / --CHANGE 99ARB06_TR new

--Increase L4 to L8 Communication to South of well

'multz' 25.0 27 31 32 38 4 4 / -- CHANGE *0.5 to match wct OK FOR T17

```

'multz' 25.0 27 31 33 38 5 7 / -- CHANGE *0.5 to match wct OK FOR T17

'multz' 1.0 27 31 31 32 5 7 / -- CHANGE *0.5 to match wct OK FOR T17

/

edit

--

--Put high Kv next to T5

box

41 41 26 27 3 10 /

tranz

2*3 14*100 /

--Put high Kv at T2 L5 and 6

--box

--29 31 32 33 5 6 /

--tranz

--12*0.5 /

EndBox

multiply

--Adjust PV to get STOOIP match with mapping

'porv' 0.991 1 52 1 62 1 1 /

'porv' 0.986 1 52 1 62 2 2 /

'porv' 0.987 1 52 1 62 3 3 /

'porv' 0.998 1 52 1 62 4 4 /

'porv' 0.996 1 52 1 62 5 5 /

'porv' 0.998 1 52 1 62 6 6 /

'porv' 0.988 1 52 1 62 7 7 /

'porv' 0.991 1 52 1 62 8 8 /

--Adjust PV to remove concretions

```



```

'porv' 0.986 1 52 1 62 1 13 /
-- 'porv' 0.5 1 52 1 62 13 13 / --PV in all Aquifer
-- 'porv' 0.5 30 36 40 49 1 3 / --PV around T3
--Reduce PV north of T19 in all good layers

'porv' 0.50 11 20 1 12 1 10 /
--Reduce PV East of T04 in L6
--'porv' 0.50 25 29 44 50 6 6 /
--RED BLOB AREA
--'porv' 10. 34 37 14 26 1 4 /
/

```

props

rock

```

-- pres comp
--u psia 1/psi
3700 4.30e-6 / --Core lab tests

```

pvtw -- taken from unpublished shell correlations

```

-- pres fvf comp visc
--u psia rb/stb 1/psi cp
3700 1.05 3.4e-6 0.33 0. /

```

pvt0 -- t2 reservoir fluid study

```

-- Rs pres bo visc
--mscf/stb psia rb/stb cp
0.028 115. 1.100 0.90 /

```

| | | | | |
|-------|-------|--------|-------|---|
| 0.101 | 415. | 1.140 | 0.67 | / |
| 0.200 | 815. | 1.192 | 0.565 | / |
| 0.295 | 1215. | 1.248 | 0.490 | / |
| 0.370 | 1515 | 1.289 | 0.452 | / |
| 0.444 | 1815. | 1.330 | 0.412 | / |
| 0.492 | 2006. | 1.357 | 0.388 | |
| | 2215 | 1.3521 | 0.396 | |
| | 2415 | 1.3475 | 0.404 | |
| | 2765 | 1.3401 | 0.418 | |
| | 3015 | 1.3349 | 0.428 | |
| | 3515 | 1.3259 | 0.448 | |
| | 4015 | 1.3170 | 0.468 | |
| | 5015 | 1.3015 | 0.508 | / |

/

pvdg

| --Press | Bg | Visc-g |
|---------|---------|--------|
| --psia | RB/MSCF | cp |
| 115. | 28.16 | 0.0111 |
| 215. | 16.11 | 0.0120 |
| 415. | 9.077 | 0.0129 |
| 815. | 4.192 | 0.0143 |
| 1215. | 2.632 | 0.0154 |
| 1515. | 2.077 | 0.0162 |
| 1815. | 1.7168 | 0.0172 |
| 2006. | 1.5628 | 0.0179 |
| 3015. | 1.046 | 0.0220 |

4015. 0.788 0.0263

5015. 0.632 0.0302

/

density -- oil water gas lb/cuft

51.03 68.3 0.067 /

--Pseudo Block Kro, Rock block Krw

--Pseudo Well Curves, Kro as Block, Krw for well

--

swof

--rel perm from Montrose and Arbroath core tests

--9 curves for Swi 0.25 to 0.65

-- Sw Krw Kro Pc

--Pseudo Block Curves

0.250 0.000 1.000 6.0

0.270 0.000 0.970 1*

0.316 0.000 0.890 4.5

0.342 0.000 0.840 1*

0.382 0.001 0.760 1*

0.447 0.004 0.610 1.5

0.513 0.017 0.440 1*

0.579 0.048 0.250 1*

0.645 0.120 0.017 0.75

0.711 0.210 0.001 1*

0.770 0.310 0.000 1*

| | | | |
|------|-------|-------|-----|
| 1.00 | 1.000 | 0.000 | 0.0 |
|------|-------|-------|-----|

/

| | | | |
|-------|-------|-------|-----|
| 0.300 | 0.000 | 1.000 | 6.0 |
|-------|-------|-------|-----|

| | | | |
|-------|-------|-------|----|
| 0.319 | 0.000 | 0.970 | 1* |
|-------|-------|-------|----|

| | | | |
|-------|-------|-------|-----|
| 0.363 | 0.000 | 0.890 | 4.5 |
|-------|-------|-------|-----|

| | | | |
|-------|-------|-------|----|
| 0.389 | 0.000 | 0.840 | 1* |
|-------|-------|-------|----|

| | | | |
|-------|-------|-------|-----|
| 0.427 | 0.001 | 0.760 | 3.0 |
|-------|-------|-------|-----|

| | | | |
|-------|-------|-------|----|
| 0.490 | 0.004 | 0.610 | 1* |
|-------|-------|-------|----|

| | | | |
|-------|-------|-------|-----|
| 0.553 | 0.017 | 0.440 | 1.5 |
|-------|-------|-------|-----|

| | | | |
|-------|-------|-------|----|
| 0.616 | 0.048 | 0.250 | 1* |
|-------|-------|-------|----|

| | | | |
|-------|-------|-------|------|
| 0.680 | 0.120 | 0.017 | 0.75 |
|-------|-------|-------|------|

| | | | |
|-------|-------|-------|----|
| 0.743 | 0.210 | 0.001 | 1* |
|-------|-------|-------|----|

| | | | |
|-------|-------|-------|----|
| 0.800 | 0.310 | 0.000 | 1* |
|-------|-------|-------|----|

| | | | |
|------|-------|-------|-----|
| 1.00 | 1.000 | 0.000 | 0.0 |
|------|-------|-------|-----|

/

| | | | |
|-------|-------|-------|-----|
| 0.350 | 0.000 | 1.000 | 6.0 |
|-------|-------|-------|-----|

| | | | |
|-------|-------|-------|----|
| 0.368 | 0.000 | 0.970 | 1* |
|-------|-------|-------|----|

| | | | |
|-------|-------|-------|-----|
| 0.409 | 0.000 | 0.890 | 4.5 |
|-------|-------|-------|-----|

| | | | |
|-------|-------|-------|----|
| 0.433 | 0.000 | 0.840 | 1* |
|-------|-------|-------|----|

| | | | |
|-------|-------|-------|-----|
| 0.469 | 0.001 | 0.760 | 3.0 |
|-------|-------|-------|-----|

| | | | |
|-------|-------|-------|-----|
| 0.528 | 0.004 | 0.610 | 1.5 |
|-------|-------|-------|-----|

| | | | |
|-------|-------|-------|----|
| 0.588 | 0.017 | 0.440 | 1* |
|-------|-------|-------|----|

| | | | |
|-------|-------|-------|----|
| 0.647 | 0.048 | 0.250 | 1* |
|-------|-------|-------|----|

| | | | |
|-------|-------|-------|------|
| 0.707 | 0.120 | 0.017 | 0.75 |
|-------|-------|-------|------|

| | | | |
|-------|-------|-------|----|
| 0.766 | 0.210 | 0.001 | 1* |
|-------|-------|-------|----|

| | | | |
|-------|-------|-------|----|
| 0.820 | 0.310 | 0.000 | 1* |
|-------|-------|-------|----|

| | | | |
|------|-------|-------|-----|
| 1.00 | 1.000 | 0.000 | 0.0 |
|------|-------|-------|-----|

/

| | | | |
|-------|-------|-------|------|
| 0.400 | 0.000 | 1.000 | 7.5 |
| 0.417 | 0.000 | 0.970 | 6.0 |
| 0.455 | 0.000 | 0.890 | 1* |
| 0.477 | 0.000 | 0.840 | 4.5 |
| 0.510 | 0.001 | 0.760 | 3.0 |
| 0.565 | 0.004 | 0.610 | 1* |
| 0.620 | 0.017 | 0.440 | 1.5 |
| 0.675 | 0.048 | 0.250 | 1* |
| 0.730 | 0.120 | 0.017 | 0.75 |
| 0.785 | 0.210 | 0.001 | 1* |
| 0.835 | 0.310 | 0.000 | 1* |
| 1.00 | 1.000 | 0.000 | 0.0 |

/

| | | | |
|-------|-------|-------|-----|
| 0.450 | 0.000 | 1.000 | 9.0 |
| 0.465 | 0.000 | 0.970 | 1* |
| 0.500 | 0.000 | 0.890 | 1* |
| 0.520 | 0.000 | 0.840 | 7.5 |
| 0.550 | 0.001 | 0.760 | 1* |
| 0.600 | 0.004 | 0.610 | 6.0 |
| 0.650 | 0.017 | 0.440 | 4.5 |
| 0.700 | 0.048 | 0.250 | 1* |
| 0.750 | 0.120 | 0.017 | 3.0 |
| 0.800 | 0.210 | 0.001 | 1.5 |
| 0.845 | 0.310 | 0.000 | 1* |
| 1.00 | 1.000 | 0.000 | 0.0 |

/

| | | | |
|-------|-------|-------|-----|
| 0.500 | 0.000 | 1.000 | 9.0 |
| 0.513 | 0.000 | 0.970 | 1* |

| | | | |
|-------|-------|-------|-----|
| 0.545 | 0.000 | 0.890 | 7.5 |
| 0.563 | 0.000 | 0.840 | 1* |
| 0.590 | 0.001 | 0.760 | 6.0 |
| 0.635 | 0.004 | 0.610 | 1* |
| 0.680 | 0.017 | 0.440 | 4.5 |
| 0.725 | 0.048 | 0.250 | 3.0 |
| 0.770 | 0.120 | 0.017 | 1* |
| 0.815 | 0.210 | 0.001 | 1.5 |
| 0.855 | 0.310 | 0.000 | 1* |
| 1.00 | 1.000 | 0.000 | 0.0 |
| / | | | |
| 0.550 | 0.000 | 1.000 | 9.0 |
| 0.562 | 0.000 | 0.970 | 1* |
| 0.589 | 0.000 | 0.890 | 7.5 |
| 0.605 | 0.000 | 0.840 | 1* |
| 0.628 | 0.001 | 0.760 | 6.0 |
| 0.668 | 0.004 | 0.610 | 1* |
| 0.707 | 0.017 | 0.440 | 4.5 |
| 0.746 | 0.048 | 0.250 | 3.0 |
| 0.785 | 0.120 | 0.017 | 1* |
| 0.825 | 0.210 | 0.001 | 1.5 |
| 0.860 | 0.310 | 0.000 | 1* |
| 1.00 | 1.000 | 0.000 | 0.0 |
| / | | | |
| 0.600 | 0.000 | 1.000 | 9.0 |
| 0.610 | 0.000 | 0.970 | 1* |
| 0.634 | 0.000 | 0.890 | 7.5 |
| 0.647 | 0.000 | 0.840 | 1* |

| | | | |
|----------------------|--------|-------|------|
| 0.667 | 0.001 | 0.760 | 6.0 |
| 0.701 | 0.004 | 0.610 | 1* |
| 0.734 | 0.017 | 0.440 | 4.5 |
| 0.768 | 0.048 | 0.250 | 3.0 |
| 0.801 | 0.120 | 0.017 | 1* |
| 0.835 | 0.210 | 0.001 | 1.5 |
| 0.865 | 0.310 | 0.000 | 1* |
| 1.00 | 1.000 | 0.000 | 0.0 |
| / | | | |
| 0.650 | 0.000 | 1.000 | 10.0 |
| 0.658 | 0.000 | 0.970 | 9.0 |
| 0.678 | 0.000 | 0.890 | 1* |
| 0.689 | 0.000 | 0.840 | 1* |
| 0.706 | 0.001 | 0.760 | 6.0 |
| 0.734 | 0.004 | 0.610 | 4.5 |
| 0.761 | 0.017 | 0.440 | 3.0 |
| 0.789 | 0.048 | 0.250 | 1* |
| 0.817 | 0.120 | 0.017 | 1.5 |
| 0.845 | 0.210 | 0.001 | 1* |
| 0.870 | 0.310 | 0.000 | 1* |
| 1.00 | 1.000 | 0.000 | 0.0 |
| / | | | |
| --Pseudo Well Curves | | | |
| 0.250 | 0 | 1 | 6.0 |
| 0.270 | 0.001 | 0.97 | 1* |
| 0.316 | 0.0074 | 0.89 | 1* |
| 0.342 | 0.013 | 0.84 | 3.0 |
| 0.382 | 0.021 | 0.76 | 1* |

| | | | |
|-------|--------|-------|-----|
| 0.447 | 0.045 | 0.61 | 1* |
| 0.513 | 0.075 | 0.44 | 1* |
| 0.579 | 0.085 | 0.25 | 1* |
| 0.645 | 0.09 | 0.017 | 1* |
| 0.711 | 0.2 | 0.001 | 1* |
| 0.770 | 0.31 | 0 | 1* |
| 1.00 | 1.000 | 0.000 | 0.0 |
| / | | | |
| 0.300 | 0 | 1 | 6.0 |
| 0.319 | 0.001 | 0.97 | 1* |
| 0.363 | 0.0074 | 0.89 | 1* |
| 0.389 | 0.013 | 0.84 | 3.0 |
| 0.427 | 0.021 | 0.76 | 1* |
| 0.490 | 0.045 | 0.61 | 1* |
| 0.553 | 0.075 | 0.44 | 1* |
| 0.616 | 0.085 | 0.25 | 1* |
| 0.680 | 0.09 | 0.017 | 1* |
| 0.743 | 0.2 | 0.001 | 1* |
| 0.800 | 0.31 | 0 | 1* |
| 1.00 | 1.000 | 0.000 | 0.0 |
| / | | | |
| 0.350 | 0 | 1 | 6.0 |
| 0.368 | 0.001 | 0.97 | 1* |
| 0.409 | 0.0074 | 0.89 | 1* |
| 0.433 | 0.013 | 0.84 | 3.0 |
| 0.469 | 0.021 | 0.76 | 1* |
| 0.528 | 0.045 | 0.61 | 1* |
| 0.588 | 0.075 | 0.44 | 1* |

| | | | |
|-------|--------|-------|-----|
| 0.647 | 0.085 | 0.25 | 1* |
| 0.707 | 0.09 | 0.017 | 1* |
| 0.766 | 0.2 | 0.001 | 1* |
| 0.820 | 0.31 | 0 | 1* |
| 1.00 | 1.000 | 0.000 | 0.0 |
| / | | | |
| 0.400 | 0 | 1 | 7.5 |
| 0.417 | 0.001 | 0.97 | 1* |
| 0.455 | 0.0074 | 0.89 | 1* |
| 0.477 | 0.013 | 0.84 | 1* |
| 0.510 | 0.021 | 0.76 | 3.0 |
| 0.565 | 0.045 | 0.61 | 1* |
| 0.620 | 0.075 | 0.44 | 1* |
| 0.675 | 0.085 | 0.25 | 1* |
| 0.730 | 0.09 | 0.017 | 1* |
| 0.785 | 0.2 | 0.001 | 1* |
| 0.835 | 0.31 | 0 | 1* |
| 1.00 | 1.000 | 0.000 | 0.0 |
| / | | | |
| 0.450 | 0 | 1 | 9.0 |
| 0.465 | 0.001 | 0.97 | 1* |
| 0.500 | 0.0074 | 0.89 | 1* |
| 0.520 | 0.013 | 0.84 | 1* |
| 0.550 | 0.021 | 0.76 | 1* |
| 0.600 | 0.045 | 0.61 | 6.0 |
| 0.650 | 0.075 | 0.44 | 1* |
| 0.700 | 0.085 | 0.25 | 3.0 |
| 0.750 | 0.09 | 0.017 | 1* |

| | | | |
|-------|--------|-------|-----|
| 0.800 | 0.2 | 0.001 | 1* |
| 0.845 | 0.31 | 0 | 1* |
| 1.00 | 1.000 | 0.000 | 1* |
| / | | | |
| 0.500 | 0 | 1 | 9.0 |
| 0.513 | 0.001 | 0.97 | 1* |
| 0.545 | 0.0074 | 0.89 | 1* |
| 0.563 | 0.013 | 0.84 | 1* |
| 0.590 | 0.021 | 0.76 | 6.0 |
| 0.635 | 0.045 | 0.61 | 1* |
| 0.680 | 0.075 | 0.44 | 1* |
| 0.725 | 0.085 | 0.25 | 3.0 |
| 0.770 | 0.09 | 0.017 | 1* |
| 0.815 | 0.2 | 0.001 | 1* |
| 0.855 | 0.31 | 0 | 1* |
| 1.00 | 1.000 | 0.000 | 0.0 |
| / | | | |
| 0.550 | 0 | 1 | 9.0 |
| 0.562 | 0.001 | 0.97 | 1* |
| 0.589 | 0.0074 | 0.89 | 1* |
| 0.605 | 0.013 | 0.84 | 1* |
| 0.628 | 0.021 | 0.76 | 6.0 |
| 0.668 | 0.045 | 0.61 | 1* |
| 0.707 | 0.075 | 0.44 | 1* |
| 0.746 | 0.085 | 0.25 | 3.0 |
| 0.785 | 0.09 | 0.017 | 1* |
| 0.825 | 0.2 | 0.001 | 1* |
| 0.860 | 0.31 | 0 | 1* |

1.00 1.000 0.000 0.0

/

0.600 0 1 9.0

0.610 0.001 0.97 1*

0.634 0.0074 0.89 1*

0.647 0.013 0.84 1*

0.667 0.021 0.76 6.0

0.701 0.045 0.61 1*

0.734 0.075 0.44 1*

0.768 0.085 0.25 3.0

0.801 0.09 0.017 1*

0.835 0.2 0.001 1*

0.865 0.31 0 1*

1.00 1.000 0.000 0.0

/

0.650 0 1 10.0

0.658 0.001 0.97 1*

0.678 0.0074 0.89 1*

0.689 0.013 0.84 1*

0.706 0.021 0.76 6.0

0.734 0.045 0.61 1*

0.761 0.075 0.44 3.0

0.789 0.085 0.25 1*

0.817 0.09 0.017 1*

0.845 0.2 0.001 1*

0.870 0.31 0 1*

1.00 1.000 0.000 0.0

/

SGOF

-- Sg Krg Krog Pc

--Rock Type 1

| | | | |
|------|--------|--------|---|
| 0 | 0 | 1 | 0 |
| 0.02 | 0 | 0.9 | 0 |
| 0.05 | 0.0018 | 0.72 | 0 |
| 0.1 | 0.008 | 0.5 | 0 |
| 0.15 | 0.025 | 0.32 | 0 |
| 0.2 | 0.068 | 0.19 | 0 |
| 0.25 | 0.13 | 0.1 | 0 |
| 0.3 | 0.21 | 0.0475 | 0 |
| 0.35 | 0.31 | 0.015 | 0 |
| 0.4 | 0.43 | 0.0045 | 0 |
| 0.47 | 0.58 | 0.001 | 0 |
| 0.5 | 0.65 | 0 | 0 |
| 0.55 | 0.75 | 0 | 0 |
| 0.6 | 0.85 | 0 | 0 |
| 0.75 | 1 | 0 | 0 |

/

--Rock Type 2

| | | | |
|----------|--------|------|---|
| 0 | 0 | 1 | 0 |
| 0.018667 | 0 | 0.9 | 0 |
| 0.046667 | 0.0018 | 0.72 | 0 |
| 0.093333 | 0.008 | 0.5 | 0 |
| 0.14 | 0.025 | 0.32 | 0 |
| 0.186667 | 0.068 | 0.19 | 0 |

```

0.233333  0.13  0.1  0
    0.28  0.21  0.0475  0
0.326667  0.31  0.015  0
0.373333  0.43  0.0045  0
0.438667  0.58  0.001  0
0.466667  0.65   0  0
0.513333  0.75   0  0
    0.56  0.85   0  0
    0.7   1    0  0

```

/

--Rock Type 3

```

    0    0    1    0
0.017333    0  0.9  0
0.043333  0.0018  0.72  0
0.086667  0.008   0.5  0
    0.13  0.025   0.32  0
0.173333  0.068   0.19  0
0.216667  0.13    0.1  0
    0.26  0.21  0.0475  0
0.303333  0.31  0.015  0
0.346667  0.43  0.0045  0
0.407333  0.58  0.001  0
0.433333  0.65   0  0
0.476667  0.75   0  0
    0.52  0.85   0  0
    0.65   1    0  0

```

/

--Rock Type 4

| | | | |
|-------|--------|--------|---|
| 0 | 0 | 1 | 0 |
| 0.016 | 0 | 0.9 | 0 |
| 0.04 | 0.0018 | 0.72 | 0 |
| 0.08 | 0.008 | 0.5 | 0 |
| 0.12 | 0.025 | 0.32 | 0 |
| 0.16 | 0.068 | 0.19 | 0 |
| 0.2 | 0.13 | 0.1 | 0 |
| 0.24 | 0.21 | 0.0475 | 0 |
| 0.28 | 0.31 | 0.015 | 0 |
| 0.32 | 0.43 | 0.0045 | 0 |
| 0.376 | 0.58 | 0.001 | 0 |
| 0.4 | 0.65 | 0 | 0 |
| 0.44 | 0.75 | 0 | 0 |
| 0.48 | 0.85 | 0 | 0 |
| 0.6 | 1 | 0 | 0 |

/

--Rock Type 5

| | | | |
|----------|--------|--------|---|
| 0 | 0 | 1 | 0 |
| 0.014667 | 0 | 0.9 | 0 |
| 0.036667 | 0.0018 | 0.72 | 0 |
| 0.073333 | 0.008 | 0.5 | 0 |
| 0.11 | 0.025 | 0.32 | 0 |
| 0.146667 | 0.068 | 0.19 | 0 |
| 0.183333 | 0.13 | 0.1 | 0 |
| 0.22 | 0.21 | 0.0475 | 0 |
| 0.256667 | 0.31 | 0.015 | 0 |
| 0.293333 | 0.43 | 0.0045 | 0 |
| 0.344667 | 0.58 | 0.001 | 0 |

```

0.366667  0.65    0  0
0.403333  0.75    0  0
0.44  0.85    0  0
0.55    1    0  0
/
--Rock Type 6
0    0    1  0
0.013333  0  0.9  0
0.033333  0.0018  0.72  0
0.066667  0.008  0.5  0
0.1  0.025  0.32  0
0.133333  0.068  0.19  0
0.166667  0.13  0.1  0
0.2  0.21  0.0475  0
0.233333  0.31  0.015  0
0.266667  0.43  0.0045  0
0.313333  0.58  0.001  0
0.333333  0.65    0  0
0.366667  0.75    0  0
0.4  0.85    0  0
0.5    1    0  0
/

```

```

--Rock Type 7
0    0    1  0
0.012  0  0.9  0
0.03  0.0018  0.72  0
0.06  0.008  0.5  0
0.09  0.025  0.32  0

```

| | | | |
|-------|-------|--------|---|
| 0.12 | 0.068 | 0.19 | 0 |
| 0.15 | 0.13 | 0.1 | 0 |
| 0.18 | 0.21 | 0.0475 | 0 |
| 0.21 | 0.31 | 0.015 | 0 |
| 0.24 | 0.43 | 0.0045 | 0 |
| 0.282 | 0.58 | 0.001 | 0 |
| 0.3 | 0.65 | 0 | 0 |
| 0.33 | 0.75 | 0 | 0 |
| 0.36 | 0.85 | 0 | 0 |
| 0.45 | 1 | 0 | 0 |

/

--Rock Type 8

| | | | |
|----------|--------|--------|---|
| 0 | 0 | 1 | 0 |
| 0.010667 | 0 | 0.9 | 0 |
| 0.026667 | 0.0018 | 0.72 | 0 |
| 0.053333 | 0.008 | 0.5 | 0 |
| 0.08 | 0.025 | 0.32 | 0 |
| 0.106667 | 0.068 | 0.19 | 0 |
| 0.133333 | 0.13 | 0.1 | 0 |
| 0.16 | 0.21 | 0.0475 | 0 |
| 0.186667 | 0.31 | 0.015 | 0 |
| 0.213333 | 0.43 | 0.0045 | 0 |
| 0.250667 | 0.58 | 0.001 | 0 |
| 0.266667 | 0.65 | 0 | 0 |
| 0.293333 | 0.75 | 0 | 0 |
| 0.32 | 0.85 | 0 | 0 |
| 0.4 | 1 | 0 | 0 |

/

--Rock Type 9

| | | | |
|----------|--------|--------|---|
| 0 | 0 | 1 | 0 |
| 0.009333 | 0 | 0.9 | 0 |
| 0.023333 | 0.0018 | 0.72 | 0 |
| 0.046667 | 0.008 | 0.5 | 0 |
| 0.07 | 0.025 | 0.32 | 0 |
| 0.093333 | 0.068 | 0.19 | 0 |
| 0.116667 | 0.13 | 0.1 | 0 |
| 0.14 | 0.21 | 0.0475 | 0 |
| 0.163333 | 0.31 | 0.015 | 0 |
| 0.186667 | 0.43 | 0.0045 | 0 |
| 0.219333 | 0.58 | 0.001 | 0 |
| 0.233333 | 0.65 | 0 | 0 |
| 0.256667 | 0.75 | 0 | 0 |
| 0.28 | 0.85 | 0 | 0 |
| 0.35 | 1 | 0 | 0 |

/

-- Sg Krg Krog Pc

--Rock Type 10 (1)

| | | | |
|------|--------|--------|---|
| 0 | 0 | 1 | 0 |
| 0.02 | 0 | 0.9 | 0 |
| 0.05 | 0.0018 | 0.72 | 0 |
| 0.1 | 0.008 | 0.5 | 0 |
| 0.15 | 0.025 | 0.32 | 0 |
| 0.2 | 0.068 | 0.19 | 0 |
| 0.25 | 0.13 | 0.1 | 0 |
| 0.3 | 0.21 | 0.0475 | 0 |
| 0.35 | 0.31 | 0.015 | 0 |

| | | | |
|------|------|--------|---|
| 0.4 | 0.43 | 0.0045 | 0 |
| 0.47 | 0.58 | 0.001 | 0 |
| 0.5 | 0.65 | 0 | 0 |
| 0.55 | 0.75 | 0 | 0 |
| 0.6 | 0.85 | 0 | 0 |
| 0.75 | 1 | 0 | 0 |

/

--Rock Type 11 (2)

| | | | |
|----------|--------|--------|---|
| 0 | 0 | 1 | 0 |
| 0.018667 | 0 | 0.9 | 0 |
| 0.046667 | 0.0018 | 0.72 | 0 |
| 0.093333 | 0.008 | 0.5 | 0 |
| 0.14 | 0.025 | 0.32 | 0 |
| 0.186667 | 0.068 | 0.19 | 0 |
| 0.233333 | 0.13 | 0.1 | 0 |
| 0.28 | 0.21 | 0.0475 | 0 |
| 0.326667 | 0.31 | 0.015 | 0 |
| 0.373333 | 0.43 | 0.0045 | 0 |
| 0.438667 | 0.58 | 0.001 | 0 |
| 0.466667 | 0.65 | 0 | 0 |
| 0.513333 | 0.75 | 0 | 0 |
| 0.56 | 0.85 | 0 | 0 |
| 0.7 | 1 | 0 | 0 |

/

--Rock Type 12 (3)

| | | | |
|----------|--------|------|---|
| 0 | 0 | 1 | 0 |
| 0.017333 | 0 | 0.9 | 0 |
| 0.043333 | 0.0018 | 0.72 | 0 |

| | | | |
|----------|-------|--------|---|
| 0.086667 | 0.008 | 0.5 | 0 |
| 0.13 | 0.025 | 0.32 | 0 |
| 0.173333 | 0.068 | 0.19 | 0 |
| 0.216667 | 0.13 | 0.1 | 0 |
| 0.26 | 0.21 | 0.0475 | 0 |
| 0.303333 | 0.31 | 0.015 | 0 |
| 0.346667 | 0.43 | 0.0045 | 0 |
| 0.407333 | 0.58 | 0.001 | 0 |
| 0.433333 | 0.65 | 0 | 0 |
| 0.476667 | 0.75 | 0 | 0 |
| 0.52 | 0.85 | 0 | 0 |
| 0.65 | 1 | 0 | 0 |

/

--Rock Type 13 (4)

| | | | |
|-------|--------|--------|---|
| 0 | 0 | 1 | 0 |
| 0.016 | 0 | 0.9 | 0 |
| 0.04 | 0.0018 | 0.72 | 0 |
| 0.08 | 0.008 | 0.5 | 0 |
| 0.12 | 0.025 | 0.32 | 0 |
| 0.16 | 0.068 | 0.19 | 0 |
| 0.2 | 0.13 | 0.1 | 0 |
| 0.24 | 0.21 | 0.0475 | 0 |
| 0.28 | 0.31 | 0.015 | 0 |
| 0.32 | 0.43 | 0.0045 | 0 |
| 0.376 | 0.58 | 0.001 | 0 |
| 0.4 | 0.65 | 0 | 0 |
| 0.44 | 0.75 | 0 | 0 |
| 0.48 | 0.85 | 0 | 0 |

0.6 1 0 0

/

--Rock Type 14 (5)

0 0 1 0

0.014667 0 0.9 0

0.036667 0.0018 0.72 0

0.073333 0.008 0.5 0

0.11 0.025 0.32 0

0.146667 0.068 0.19 0

0.183333 0.13 0.1 0

0.22 0.21 0.0475 0

0.256667 0.31 0.015 0

0.293333 0.43 0.0045 0

0.344667 0.58 0.001 0

0.366667 0.65 0 0

0.403333 0.75 0 0

0.44 0.85 0 0

0.55 1 0 0

/

--Rock Type 15 (6)

0 0 1 0

0.013333 0 0.9 0

0.033333 0.0018 0.72 0

0.066667 0.008 0.5 0

0.1 0.025 0.32 0

0.133333 0.068 0.19 0

0.166667 0.13 0.1 0

0.2 0.21 0.0475 0

| | | | |
|----------|------|--------|---|
| 0.233333 | 0.31 | 0.015 | 0 |
| 0.266667 | 0.43 | 0.0045 | 0 |
| 0.313333 | 0.58 | 0.001 | 0 |
| 0.333333 | 0.65 | 0 | 0 |
| 0.366667 | 0.75 | 0 | 0 |
| 0.4 | 0.85 | 0 | 0 |
| 0.5 | 1 | 0 | 0 |

/

--Rock Type 16 (7)

| | | | |
|-------|--------|--------|---|
| 0 | 0 | 1 | 0 |
| 0.012 | 0 | 0.9 | 0 |
| 0.03 | 0.0018 | 0.72 | 0 |
| 0.06 | 0.008 | 0.5 | 0 |
| 0.09 | 0.025 | 0.32 | 0 |
| 0.12 | 0.068 | 0.19 | 0 |
| 0.15 | 0.13 | 0.1 | 0 |
| 0.18 | 0.21 | 0.0475 | 0 |
| 0.21 | 0.31 | 0.015 | 0 |
| 0.24 | 0.43 | 0.0045 | 0 |
| 0.282 | 0.58 | 0.001 | 0 |
| 0.3 | 0.65 | 0 | 0 |
| 0.33 | 0.75 | 0 | 0 |
| 0.36 | 0.85 | 0 | 0 |
| 0.45 | 1 | 0 | 0 |

/

--Rock Type 17 (8)

| | | | |
|----------|---|-----|---|
| 0 | 0 | 1 | 0 |
| 0.010667 | 0 | 0.9 | 0 |

| | | | |
|----------|--------|--------|---|
| 0.026667 | 0.0018 | 0.72 | 0 |
| 0.053333 | 0.008 | 0.5 | 0 |
| 0.08 | 0.025 | 0.32 | 0 |
| 0.106667 | 0.068 | 0.19 | 0 |
| 0.133333 | 0.13 | 0.1 | 0 |
| 0.16 | 0.21 | 0.0475 | 0 |
| 0.186667 | 0.31 | 0.015 | 0 |
| 0.213333 | 0.43 | 0.0045 | 0 |
| 0.250667 | 0.58 | 0.001 | 0 |
| 0.266667 | 0.65 | 0 | 0 |
| 0.293333 | 0.75 | 0 | 0 |
| 0.32 | 0.85 | 0 | 0 |
| 0.4 | 1 | 0 | 0 |

/

--Rock Type 18 (9)

| | | | |
|----------|--------|--------|---|
| 0 | 0 | 1 | 0 |
| 0.009333 | 0 | 0.9 | 0 |
| 0.023333 | 0.0018 | 0.72 | 0 |
| 0.046667 | 0.008 | 0.5 | 0 |
| 0.07 | 0.025 | 0.32 | 0 |
| 0.093333 | 0.068 | 0.19 | 0 |
| 0.116667 | 0.13 | 0.1 | 0 |
| 0.14 | 0.21 | 0.0475 | 0 |
| 0.163333 | 0.31 | 0.015 | 0 |
| 0.186667 | 0.43 | 0.0045 | 0 |
| 0.219333 | 0.58 | 0.001 | 0 |
| 0.233333 | 0.65 | 0 | 0 |
| 0.256667 | 0.75 | 0 | 0 |

0.28 0.85 0 0

0.35 1 0 0

/

-- include aquifer influx function

--include

-- 'AQU_INF.PRN' /

TRACER

-- salt water injection

'SO4' 'WAT' /

-- formation brine

'BA' 'WAT' /

-- aquifer water

'AQU' 'WAT' /

-- connate water

'CON' 'WAT' /

/

-- Polymer viscosity

-- HPAM - polyacrylamide

-- Polymer Improved Oil Recovery, K.S. Sorbie, pg 42 Figure 3.3

-- Polymer concentration (ppm) Viscosity (cP)

-- 400 4

-- 800 10

| | | |
|----|------|----|
| -- | 1000 | 14 |
| -- | 1200 | 19 |
| -- | 1600 | 30 |

-- 1 ppm = 4.259E-04 lb/stb

PLYVISC

-- concentration (lb/stb) viscosity multiplier (vis[wat] = 0.33 cP)

| | |
|--------|-------|
| 0.0000 | 1.00 |
| 0.1704 | 12.12 |
| 0.3407 | 30.30 |
| 0.4259 | 42.42 |
| 0.5111 | 57.57 |
| 0.6814 | 90.90 |

/

-- Residual resistance factor

-- Medium Molecular Weight Polymer ca. 1.5

-- Polymer Improved Oil Recovery, K.S. Sorbie, pg 147 Figure 5.10

-- rock density = 2.65 gm/cc

-- = 929 lb/stn

PLYROCK

0.16 1.5 929.0 1 3.8E-06 /

0.16 1.5 929.0 1 3.8E-06 /

0.16 1.5 929.0 1 3.8E-06 /
 0.16 1.5 929.0 1 3.8E-06 /
 0.16 1.5 929.0 1 3.8E-06 /
 0.16 1.5 929.0 1 3.8E-06 /
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 0.16 1.5 929.0 1 3.8E-06 /
 0.16 1.5 929.0 1 3.8E-06 /
 0.16 1.5 929.0 1 3.8E-06 /
 0.16 1.5 929.0 1 3.8E-06 /
 0.16 1.5 929.0 1 3.8E-06 /
 0.16 1.5 929.0 1 3.8E-06 /
 0.16 1.5 929.0 1 3.8E-06 /
 0.16 1.5 929.0 1 3.8E-06 /
 0.16 1.5 929.0 1 3.8E-06 /
 0.16 1.5 929.0 1 3.8E-06 /

-- Polymer adsorption

-- HPAM in 2% NaCl

-- Polymer Improved Oil Recovery, K.S. Sorbie, pg 149 Figure 5.13

-- Concentration (ppm) Adsorption (microgram/gram)

-- 0 0.0
 -- 40 3.5
 -- 80 3.6
 -- 120 3.7
 -- 160 3.8

-- 1000 3.8

-- 1 ppm = 4.259E-04 lb/stb

-- 1 microgram/gram = 1E-06 gram/gram = 1E-06 lb/lb

PLYADS

-- Concentration (lb/stb) Adsorption (lb/lb)

| | |
|---------|-----------|
| 0 | 0.0E-06 |
| 0.01704 | 3.5E-06 |
| 0.03407 | 3.6E-06 |
| 0.05111 | 3.7E-06 |
| 0.06814 | 3.8E-06 |
| 0.4259 | 3.8E-06 / |
| 0 | 0.0E-06 |
| 0.01704 | 3.5E-06 |
| 0.03407 | 3.6E-06 |
| 0.05111 | 3.7E-06 |
| 0.06814 | 3.8E-06 |
| 0.4259 | 3.8E-06 / |
| 0 | 0.0E-06 |
| 0.01704 | 3.5E-06 |
| 0.03407 | 3.6E-06 |
| 0.05111 | 3.7E-06 |
| 0.06814 | 3.8E-06 |
| 0.4259 | 3.8E-06 / |
| 0 | 0.0E-06 |
| 0.01704 | 3.5E-06 |
| 0.03407 | 3.6E-06 |
| 0.05111 | 3.7E-06 |

| | |
|---------|-----------|
| 0.06814 | 3.8E-06 |
| 0.4259 | 3.8E-06 / |
| 0 | 0.0E-06 |
| 0.01704 | 3.5E-06 |
| 0.03407 | 3.6E-06 |
| 0.05111 | 3.7E-06 |
| 0.06814 | 3.8E-06 |
| 0.4259 | 3.8E-06 / |
| 0 | 0.0E-06 |
| 0.01704 | 3.5E-06 |
| 0.03407 | 3.6E-06 |
| 0.05111 | 3.7E-06 |
| 0.06814 | 3.8E-06 |
| 0.4259 | 3.8E-06 / |
| 0 | 0.0E-06 |
| 0.01704 | 3.5E-06 |
| 0.03407 | 3.6E-06 |
| 0.05111 | 3.7E-06 |
| 0.06814 | 3.8E-06 |
| 0.4259 | 3.8E-06 / |
| 0 | 0.0E-06 |
| 0.01704 | 3.5E-06 |
| 0.03407 | 3.6E-06 |
| 0.05111 | 3.7E-06 |
| 0.06814 | 3.8E-06 |
| 0.4259 | 3.8E-06 / |
| 0 | 0.0E-06 |
| 0.01704 | 3.5E-06 |

| | |
|---------|-----------|
| 0.03407 | 3.6E-06 |
| 0.05111 | 3.7E-06 |
| 0.06814 | 3.8E-06 |
| 0.4259 | 3.8E-06 / |
| 0 | 0.0E-06 |
| 0.01704 | 3.5E-06 |
| 0.03407 | 3.6E-06 |
| 0.05111 | 3.7E-06 |
| 0.06814 | 3.8E-06 |
| 0.4259 | 3.8E-06 / |
| 0 | 0.0E-06 |
| 0.01704 | 3.5E-06 |
| 0.03407 | 3.6E-06 |
| 0.05111 | 3.7E-06 |
| 0.06814 | 3.8E-06 |
| 0.4259 | 3.8E-06 / |
| 0 | 0.0E-06 |
| 0.01704 | 3.5E-06 |
| 0.03407 | 3.6E-06 |
| 0.05111 | 3.7E-06 |
| 0.06814 | 3.8E-06 |
| 0.4259 | 3.8E-06 / |
| 0 | 0.0E-06 |
| 0.01704 | 3.5E-06 |
| 0.03407 | 3.6E-06 |
| 0.05111 | 3.7E-06 |
| 0.06814 | 3.8E-06 |
| 0.4259 | 3.8E-06 / |

| | |
|---------|-----------|
| 0 | 0.0E-06 |
| 0.01704 | 3.5E-06 |
| 0.03407 | 3.6E-06 |
| 0.05111 | 3.7E-06 |
| 0.06814 | 3.8E-06 |
| 0.4259 | 3.8E-06 / |
| 0 | 0.0E-06 |
| 0.01704 | 3.5E-06 |
| 0.03407 | 3.6E-06 |
| 0.05111 | 3.7E-06 |
| 0.06814 | 3.8E-06 |
| 0.4259 | 3.8E-06 / |
| 0 | 0.0E-06 |
| 0.01704 | 3.5E-06 |
| 0.03407 | 3.6E-06 |
| 0.05111 | 3.7E-06 |
| 0.06814 | 3.8E-06 |
| 0.4259 | 3.8E-06 / |
| 0 | 0.0E-06 |
| 0.01704 | 3.5E-06 |
| 0.03407 | 3.6E-06 |
| 0.05111 | 3.7E-06 |
| 0.06814 | 3.8E-06 |
| 0.4259 | 3.8E-06 / |
| 0 | 0.0E-06 |
| 0.01704 | 3.5E-06 |
| 0.03407 | 3.6E-06 |
| 0.05111 | 3.7E-06 |

| | |
|---------|-----------|
| 0.06814 | 3.8E-06 |
| 0.4259 | 3.8E-06 / |

TLMIXPAR

1.0 /

PLYMAX

0.4259 0.0 /

RPTPROPS

-- PROPS Reporting Options

--

'PLYVISC'

/

regions

--rptregs

-- pvt sat equ fip

-- 4*0 /

---regionalisation is as follows

--Each layer is a region

FIPNUM

3224*1 3224*2 3224*3 3224*4 3224*5 3224*6 3224*7 3224*8

3224*9 3224*10 3224*11 3224*12 3224*13

/

noecho

--

-- satnum array

include

'arbgrid/ARB_SATNUM.GRDECL' /

solution

--equil

--datum press owc owc goc goc rsvd rsvd soln

--depth dep pcow dep pcog table table meth

-- 8150 3680 8265 0 200 0 1 0 10 /

-- 8150 3680 8265 0 200 0 1 0 10 /

include

'arbgrid/ARB_SWAT.GRDECL' /

include

'arbgrid/ARB_PRESSURE.GRDECL' /

echo

DATUM

8150. /

SGAS

41912*0.0

/

noecho

include

'arbgrid/ARB_PBUB.GRDECL' /

echo

TVDPFSO4

0.0 0.0

10000 0.0 /

TVDPFBA

0.0 255.0

10000.0 255.0 /

TVDPFAQU

0.0 0.0

8265.0 0.0

8266.0 1.0

10000.0 1.0 /

TVDPFCON

0.0 1.0

8265.0 1.0

8266.0 0.0

10000.0 0.0 /

--rptrst


```
--2 0 1 0 0 0 0 0 0 1 1 0 / --outputs oil and water rel perms each time step
```

```
--rptsol
```

```
--1 2 3 4 5 6 7 8 9 10 11 12 26
```

```
--pres sor swc sg rs rs rst fip equ - - aqu swcrit
```

```
-- 0 0 0 0 0 0 2 2 0 0 0 1 / --44*0.2*10 /
```

```
include
```

```
'AQU.INC' /
```

```
AQANTRC
```

```
1 BA 255.0 /
```

```
1 AQU 1.0 /
```

```
2 BA 255.0 /
```

```
2 AQU 1.0 /
```

```
3 BA 255.0 /
```

```
3 AQU 1.0 /
```

```
4 BA 255.0 /
```

```
4 AQU 1.0 /
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5 BA 255.0 /
```

```
5 AQU 1.0 /
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6 BA 255.0 /
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6 AQU 1.0 /
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99 BA 255.0 /

99 AQU 1.0 /

/

RPTRST

BASIC=2 /

summary

--include

-- 'HIST.SUM' /

-- Field average pressure

FPR

-- Bottomhole pressure of all wells

WBHP

/

-- Field Oil Production Rate

FOPR

-- Field Water Production Rate

FWPR

-- Field Oil Production Total

FOPT

-- Field Water Production Total

FWPT

-- Field Water cut

FWCT

-- Field Water injection total

FWIT

-- Field oil recovery efficiency

FOE

--Field Polymer production rate

FCPR

--Field Polymer production total

FCPT

--Field Polymer injection rate

FCIR

--Field Polymer Injection total

FCIT

--Well Polymer production rate

WCPR

/

--Well Polymer production total

WCPT

/

--Well Polymer injection rate

WCIR

/

--Well Polymer Injection total

WCIT

/

WOPR

/

WWPR

/

WWIR

/

WOPT

/

WWPT

/

WWIT

/

WTHP

/

BWVIS

21 37 7 /

/

DATE

EXCEL

RPTONLY

schedule

noecho

RPTRST

BASIC=4 /

-- hi angle producer table 1

include

'vfp/T15NF1P.VFP' /

-- lo angle producer table 2

include

'vfp/T01NF1.VFP' /

-- hi angle producer table 3 (with glr = 800)

include

'vfp/T15GL1P.VFP' /

-- lo angle producer table 4 (with glr = 800)

include

'vfp/T01GL1.VFP' /

-- injectors

include

'vfp/T11Z.VFP' /

include

'vfp/T12.VFP' /

include

'vfp/T18.VFP' /

echo

-- max timestep 10 days during history match phase

tuning

5. 10. /

/

/

-- name group i j datum pi radius

welspecs

```
't01' 's' 21 37 8150 'oil' 1500 /
't01l' 's' 21 37 8150 'wat' 1500 2* 'NO' /
't02' 'nw' 30 32 8150 'oil' 1500 /
't03' 'c' 32 44 8150 'oil' 1500 /
't04' 's' 23 44 8150 'oil' 1500 /
't05' 'n' 40 27 8150 'oil' 1500 /
't06' 'nw' 22 26 8150 'wat' 1500 2* 'NO' /
't07' 's' 26 53 8150 'wat' 1500 2* 'NO' /
't08' 'c' 34 36 8150 'oil' 1500 /
't09' 'n' 46 25 8150 'wat' 1500 2* 'NO' /
't10' 'w' 16 27 8150 'oil' 1500 /
't10l' 'w' 16 27 8150 'wat' 1500 2* 'NO' /
't11' 'c' 33 50 8150 'wat' 1500 2* 'NO' /
't12' 's' 18 32 8150 'wat' 1500 2* 'NO' /
't13' 'c' 36 45 8150 'oil' 1500 /
't14' 'w' 14 21 8150 'oil' 1500 /
't15' 'n' 42 19 8150 'oil' 1500 /
't16' 'nw' 30 25 8150 'oil' 1500 /
't17' 'n' 37 32 8150 'oil' 1500 /
't18' 's' 27 50 8150 'wat' 1500 2* 'NO' /
't19' 'w' 15 15 8150 'oil' 1500 /
```

't20' 'nw' 28 19 8150 'oil' 1500 /
/

-- name i j k1 k2 open sat tran dw kh s
compdat
-- producers

't01' 2* 1 13 'shut' 0 0.0 0.76 0. -2.0 /
't02' 2* 1 13 'shut' 0 0.0 0.76 0. -2.0 /
't03' 2* 1 13 'shut' 0 0.0 0.76 0. 2.50 /
't04' 2* 1 13 'shut' 0 0.0 0.76 0. -3.0 /
't05' 2* 1 13 'shut' 0 0.0 0.76 0. -3.0 /
't08' 2* 1 13 'shut' 0 0.0 0.76 0. -2.0 /
't10' 2* 1 13 'shut' 0 0.0 0.76 0. -2.50 /
't13' 2* 1 13 'shut' 0 0.0 0.76 0. -1.70 /
't14' 2* 1 13 'shut' 0 0.0 0.76 0. -2. /
't15' 2* 1 13 'shut' 0 0.0 0.76 0. -2.70 /
't16' 2* 1 13 'shut' 0 0.0 0.76 0. -2.9 /
't17' 2* 1 13 'shut' 0 0.0 0.76 0. -2.4 /
't19' 2* 1 13 'shut' 0 0.0 0.76 0. 2.8 /
't20' 2* 1 13 'shut' 0 0.0 0.76 0. -2.1 /

-- injectors

't06' 2* 1 13 'shut' 0 0.0 0.76 0. 0.3 /
't07' 2* 1 13 'shut' 0 0.0 0.76 0. 2.3 /
't09' 2* 1 13 'shut' 0 0.0 0.76 0. 0.6 /

't01' 2* 1 13 'shut' 0 0.0 0.76 0.0.0 /
 't10' 2* 1 13 'shut' 0 0.0 0.76 0.0.0 /
 't11' 2* 1 13 'shut' 0 0.0 0.76 0.1.30 /
 't12' 2* 1 13 'shut' 0 0.0 0.76 0.-1.80 /
 't18' 2* 1 13 'shut' 0 0.0 0.76 0.0.9 /

/

-- well open ctl oil wat gas liq res bhp thp tab alq

wconprod

't01' 'shut' 'bhp' 1* 1* 1* 1* 1* 1500 1* 2 1* /
 't02' 'shut' 'bhp' 1* 1* 1* 1* 1* 1500 1* 2 1* /
 't03' 'shut' 'bhp' 1* 1* 1* 1* 1* 1500 1* 2 1* /
 't04' 'shut' 'bhp' 1* 1* 1* 1* 1* 1500 1* 2 1* /
 't05' 'shut' 'bhp' 1* 1* 1* 1* 1* 1500 1* 2 1* /
 't08' 'shut' 'bhp' 1* 1* 1* 1* 1* 1500 1* 2 1* /
 't10' 'shut' 'bhp' 1* 1* 1* 1* 1* 1500 1* 1 1* /
 't13' 'shut' 'bhp' 1* 1* 1* 1* 1* 1500 1* 2 1* /
 't14' 'shut' 'bhp' 1* 1* 1* 1* 1* 1500 1* 1 1* /
 't15' 'shut' 'bhp' 1* 1* 1* 1* 1* 1500 1* 1 1* /
 't16' 'shut' 'bhp' 1* 1* 1* 1* 1* 1500 1* 1 1* /
 't17' 'shut' 'bhp' 1* 1* 1* 1* 1* 1500 1* 2 1* /
 't19' 'shut' 'bhp' 1* 1* 1* 1* 1* 1500 1* 1 1* /
 't20' 'shut' 'bhp' 1* 1* 1* 1* 1* 1500 1* 1 1* /

/

-- well phase open ctl surf resv vrf vrc bhp thp tab

wconinj

```
't06' 'water' 'shut' 'bhp' 1* 1* 1* 'none' 7500 1* 1 /
't07' 'water' 'shut' 'bhp' 1* 1* 1* 'none' 7500 1* 1 /
't09' 'water' 'shut' 'bhp' 1* 1* 1* 'none' 7500 1* 1 /
't011' 'water' 'shut' 'bhp' 1* 1* 1* 'none' 7500 1* 1 /
't101' 'water' 'shut' 'bhp' 1* 1* 1* 'none' 7500 1* 1 /
't111' 'water' 'shut' 'bhp' 1* 1* 1* 'none' 7500 1* 1 /
't12' 'water' 'shut' 'bhp' 1* 1* 1* 'none' 7500 1* 2 /
't18' 'water' 'shut' 'bhp' 1* 1* 1* 'none' 7500 1* 3 /
/
```

WPOLYMER

```
't06' 0.0 0.0 /
't07' 0.0 0.0 /
't09' 0.0 0.0 /
't011' 0.0 0.0 /
't101' 0.0 0.0 /
't111' 0.0 0.0 /
't12' 0.0 0.0 /
't18' 0.0 0.0 /
```

/

-- Set all injection blocks rel perm

compinjk

```
't06' 2* 1 4 0.31 /
't06' 2* 5 12 1.0 /
't07' 2* 1 4 0.31 /
't07' 2* 5 10 1.0 /
't09' 2* 1 7 0.31 /
```


't09' 2* 8 10 1.0 /
 't11' 2* 1 7 0.31 /
 't11' 2* 8 11 1.0 /
 't12' 2* 1 4 0.31 /
 't12' 2* 5 8 1.0 /
 't18' 2* 2 8 0.31 /
 't18' 2* 9 11 1.0 /
 /

WTRACER

't06' SO4 2780.0 /
 't07' SO4 2780.0 /
 't09' SO4 2780.0 /
 't011' SO4 2780.0 /
 't101' SO4 2780.0 /
 't101' SO4 2780.0 /
 't11' SO4 2780.0 /
 't12' SO4 2780.0 /
 't18' SO4 2780.0 /
 /

--rptsched

--1 2 3 4 5 6 7 8 9 10 11 12 13 14 15

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

-- +lay ed conv

-- 0 0 0 0 0 0 0 0 2 0 0 0 0 0 /

include

'sched/APR90.SCH' /

--rptsched

--1 2 3 4 5 6 7 8 9 10 11 12 13 14 15

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

-- +lay ed conv

-- 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 /

welopen

't01' 'open' /

't04' 'open' /

't05' 'open' /

't08' 'open' /

/

compdat

't01' 2* 1 1 'open' 13 0.0 0.76 0. -2.0 /

't01' 2* 2 2 'open' 11 0.0 0.76 0. -2.0 /

't01' 2* 3 5 'open' 12 0.0 0.76 0. -2.0 /

't04' 2* 1 2 'open' 13 0.0 0.76 0. -3.2 /

't04' 2* 3 3 'open' 12 0.0 0.76 0. -3.2 /

't04' 2* 4 4 'open' 13 0.0 0.76 0. -3.2 /

't04' 2* 5 5 'open' 15 0.0 0.76 0. -3.2 /

-- 't05' 2* 1 1 'open' 10 0.0 0.76 0. -2.8 /

-- 't05' 2* 2 2 'open' 11 0.0 0.76 0. -2.8 /

-- 't05' 2* 3 3 'open' 10 0.0 0.76 0. -2.8 /

-- 't05' 2* 4 4 'open' 12 0.0 0.76 0. -2.8 /

```
't05' 2* 1 1 'open' 10 0.0 0.76 1609. -2.8 /
't05' 2* 2 2 'open' 11 0.0 0.76 261. -2.8 /
't05' 2* 3 3 'open' 10 0.0 0.76 1566. -2.8 /
't05' 2* 4 4 'open' 12 0.0 0.76 914. -2.8 /
't08' 2* 1 2 'open' 11 0.0 0.76 0. -2.0 /
't08' 2* 3 3 'open' 12 0.0 0.76 0. -2.0 /
't08' 2* 4 4 'open' 13 0.0 0.76 0. -2.0 /
```

```
/
```

```
-- well pi derived from well test data
```

```
welpi
```

```
't01' 15.3 /
```

```
't04' 8.75 /
```

```
't05' 12.1 /
```

```
't08' 8.5 /
```

```
/
```

```
-----
include
```

```
'sched/MAY90.SCH' /
```

```
welopen
```

```
't03' 'open' /
```

```
't10' 'open' /
```

```
/
```

```
compdat
```

```
't03' 2* 1 1 'open' 11 0.0 0.76 0. 2.4 /
```

```
't03' 2* 2 3 'open' 10 0.0 0.76 0. 2.4 /
```

```
't03' 2* 4 5 'open' 12 0.0 0.76 0. 2.4 /
```

```
't03' 2* 6 6 'open' 13 0.0 0.76 0. 2.4 /
--'t03' 2* 7 7 'open' 14 0.0 0.76 0. 2.4 /
't10' 2* 1 1 'open' 16 0.0 0.76 0. -2.3 /
't10' 2* 2 2 'open' 12 0.0 0.76 0. -2.3 /
't10' 2* 3 3 'open' 15 0.0 0.76 0. -2.3 /
/
```

```
-- well pi derived from well test data
```

```
welpi
```

```
't03' 12.0 /
't10' 4.5 /
/
```

```
-----
include
```

```
'sched/JUN90.SCH' /
```

```
welopen
```

```
't06' 'open' /
't07' 'open' /
't09' 'open' /
/
```

```
compdat
```

```
't06' 2* 1 12 'open' 0 0.0 0.76 0. 0.3 /
't07' 2* 1 10 'open' 0 0.0 0.76 0. 2.3 /
't09' 2* 1 10 'open' 0 0.0 0.76 0. 0.6 /
/
```

-- well pi derived from well test data

welpi

't06' 0.64 /

't07' 2.98 /

't09' 2.25 /

/

include

'sched/JUL90.SCH' /

include

'sched/AUG90.SCH' /

-- t11 RFT @ 24/8/90 in include file

--Rate adjustment for T6 and T5 well tests in include file

include

'sched/SEP90.SCH' /

include

'sched/OCT90.SCH' /

welopen

't09' 'shut' 0 0 0 /

/

-- t11Z RFT data

--rptsched

--1 2 3 4 5 6 7 8 9 10 11 12 13 14 15

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

-- +lay ed conv

-- 0 0 0 0 0 0 2 0 0 0 0 0 0 0 /

dates

10 'oct' 1990 /

/

--rptsched

--1 2 3 4 5 6 7 8 9 10 11 12 13 14 15

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

-- +lay ed conv

-- 0 0 0 0 0 0 0 0 0 0 0 0 0 0 /

welopen

't11' 'open' /

/

compdat

't11' 2* 1 11 'open' 0 0.0 0.76 0.1.3 /

/

weltarg

't11' 'WRAT' 9224 /

/

WEFAC

'T11' 0.182 /

/

-- well pi derived from well test data

welpi

't11' 7.17 /

/

include

'sched/NOV90.SCH' /

dates

16 'nov' 1990 /

/

-- reduce time steps during pbu

tuning

1. 10. /

/

/

welopen

't01' 'shut' /

't03' 'shut' /

't04' 'shut' /

't05' 'shut' /

't08' 'shut' /

't10' 'shut' /

't07' 'shut' /

't11' 'shut' /

't06' 'shut' 0 0 0 /

/

include

'sched/DEC90.SCH' /

welopen

't01' 'open' /

't03' 'open' /

't04' 'open' /

't05' 'open' /

't08' 'open' /

't10' 'open' /

't07' 'open' /

't11' 'open' /

't12' 'open' /

/

compdat

't12' 2* 1 1 'open' 0 0.0 0.76 0. -4.1 /

't12' 2* 2 8 'open' 0 0.0 0.76 0. 2.0 /

/

-- well pi derived from well test data

--welpi

-- 't12' 9.9 /

--/

--rptsched

--1 2 3 4 5 6 7 8 9 10 11 12 13 14 15

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new


```

--          +lay          ed conv
-- 0 0 0 0 0 0 0 2 2 0 0 0 2 0 /

-----

include

'sched/JAN91.SCH' /

-- t13 rft data

--rptsched

--1 2 3 4 5 6 7 8 9 10 11 12 13 14 15

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

--          +lay          ed conv
-- 0 0 0 0 0 0 2 0 0 0 0 0 0 0 /

dates

4 'jan' 1991 /

/

--rptsched

--1 2 3 4 5 6 7 8 9 10 11 12 13 14 15

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

--          +lay          ed conv
-- 0 0 0 0 0 0 0 0 0 0 0 0 0 0 /

dates

22 'jan' 1991 /

/

-- reduce time steps during pbu

tuning

```

1. 10. /

/

/

welopen

't01' 'shut' /

't03' 'shut' /

't04' 'shut' /

't05' 'shut' /

't08' 'shut' /

't10' 'shut' /

't07' 'shut' /

't11' 'shut' /

't12' 'shut' /

/

include

'sched/FEB91.SCH' /

welopen

't01' 'open' /

't03' 'open' /

't04' 'open' /

't05' 'open' /

't08' 'open' /

't10' 'open' /

't07' 'open' /

't11' 'open' /

't12' 'open' /

```

't13' 'open' /
/
compdat
't13' 2* 1 1 'open' 14 0.0 0.76 0. -0.3 /
't13' 2* 2 2 'open' 12 0.0 0.76 0. -0.3 /
't13' 2* 3 3 'open' 13 0.0 0.76 0. -0.3 /
't13' 2* 4 4 'open' 14 0.0 0.76 0. -0.3 /
't13' 2* 5 5 'open' 16 0.0 0.76 0. -0.3 /
/
-- well pi derived from well test data
welpi
't13' 5.05 /
/

-- MPLT data t11, t12, t13
--rptsched
--1 2 3 4 5 6 7 8 9 10 11 12 13 14 15
--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new
--          +lay          ed conv
-- 0 0 0 0 0 0 0 0 2 0 0 0 0 0 /

-----

include

'sched/MAR91.SCH' /
-- field s/d 24-29 mar 91
--rptsched
--1 2 3 4 5 6 7 8 9 10 11 12 13 14 15
--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

```

```

--          +lay          ed conv

-- 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 /

dates

  24 'mar' 1991 /

/

-- reduce time steps during pbu

tuning

1. 10. /

/

/

welopen

't01' 'shut' /

't03' 'shut' /

't04' 'shut' /

't05' 'shut' /

't08' 'shut' /

't10' 'shut' /

't13' 'shut' /

't07' 'shut' /

't11' 'shut' /

't12' 'shut' /

/

dates

  30 'mar' 1991 /

/

welopen

't01' 'open' /

't03' 'open' /

```

```
't04' 'open' /
't05' 'open' /
't08' 'open' /
't10' 'open' /
't13' 'open' /
't07' 'open' /
't11' 'open' /
't12' 'open' /
/
-----
include
    'sched/APR91.SCH' /

-- field s/d 15-22 apr 91
dates
    15 'apr' 1991 /
/
-- reduce time steps during pbu
tuning
    1. 10. /
/
/
welopen
    't01' 'shut' /
    't03' 'shut' /
    't04' 'shut' /
    't05' 'shut' /
    't08' 'shut' /
```

```
't10' 'shut' /
't13' 'shut' /
't07' 'shut' /
't11' 'shut' /
't12' 'shut' /
/
dates
  22 'apr' 1991 /
/
welopen
't01' 'open' /
't03' 'open' /
't04' 'open' /
't05' 'open' /
't08' 'open' /
't10' 'open' /
't13' 'open' /
't07' 'open' /
't11' 'open' /
't12' 'open' /
/
-----
include
  'sched/MAY91.SCH' /

-- MPLT data t01, t12, t04
--rptsched
--1 2 3 4 5 6 7 8 9 10 11 12 13 14 15
```

```

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

--          +lay          ed conv

-- 0 0 0 0 0 0 0 0 2 0 0 0 0 0 /

-----

include

'sched/JUN91.SCH' /

--rptsched

--1 2 3 4 5 6 7 8 9 10 11 12 13 14 15

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

--          +lay          ed conv

-- 0 0 0 0 0 0 0 0 0 0 0 0 0 0 /

welopen

't15' 'open' /

/

compmat

't15' 2* 1 2 'open' 12 0.0 0.76 0. -2.7 /

't15' 2* 3 3 'open' 14 0.0 0.76 0. -2.7 /

't15' 2* 4 4 'open' 13 0.0 0.76 0. -2.7 /

/

-- well pi derived from well test data

welpi

't15' 10.3 /

/

-----

include

```

```

'sched/JUL91.SCH' /

-- t16 rft data

--rptsched

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

--          +lay          ed conv
-- 0 0 0 0 0 0 2 0 0 0 0 0 0 0 /

dates

19 'jul' 1991 /

/

--rptsched

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

--          +lay          ed conv
-- 0 0 0 0 0 0 0 0 0 0 0 0 0 0 /

-----

include

'sched/AUG91.SCH' /

--compdat

-- 't12' 2* 1 1 'open' 0 0.0 0.76 0. -1.0 /

-- 't12' 2* 2 8 'open' 0 0.0 0.76 0. 0.1 /

--/

--welpi

-- 't12' 9.9 /

```


--/

welopen

't16' 'open' /

/

compdat

't16' 2* 1 1 'open' 11 0.0 0.76 0. -2.9 /

't16' 2* 2 3 'open' 12 0.0 0.76 0. -2.9 /

/

-- well pi derived from well test data

welpi

't16' 7.17 /

/

-- MPLT data t15, t16

--rptsched

--1 2 3 4 5 6 7 8 9 10 11 12 13 14 15

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

-- +lay ed conv

-- 0 0 0 0 0 0 0 0 2 0 0 0 0 0 /

include

'sched/SEP91.SCH' /

--rptsched

--1 2 3 4 5 6 7 8 9 10 11 12 13 14 15

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

-- +lay ed conv

-- 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 /

-- t3 s/d for adjacent drilling work

dates

7 'sep' 1991 /

/

welopen

't03' 'shut' /

/

-- t10 s/d for adjacent drilling work

dates

23 'sep' 1991 /

/

welopen

't10' 'shut' /

/

include

'sched/OCT91.SCH' /

-- t03 opened

dates

15 'oct' 1991 /

/

welopen

```

        't03' 'open' /
/
-----

include

    'sched/NOV91.SCH' /

-- t10 opened

dates

    15 'nov' 1991 /
/

welopen

    't10' 'open' /
/

-----

-- t17 rft data

--rptsched

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

--          +lay          ed conv

-- 0 0 0 0 0 0 2 0 0 0 0 0 0 0 /

include

    'sched/DEC91.SCH' /

-- MPLT t03

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

--          +lay          ed conv

--0 0 0 0 0 0 0 0 0 0 0 0 0 0 /

```

dates

18 'dec' 1991 /

/

-- reduce time steps during pbu

tuning

1. 10. /

/

/

-- shut in wells for constrained production 20 mbd approx / t17 opened

welopen

't03' 'shut' /

't04' 'shut' /

't05' 'shut' /

't08' 'shut' /

't13' 'shut' /

't16' 'shut' /

't17' 'open' /

/

compdat

't17' 2* 1 1 'open' 10 0.0 0.76 0. -2.4 /

't17' 2* 2 2 'open' 12 0.0 0.76 0. -2.4 /

't17' 2* 3 3 'open' 11 0.0 0.76 0. -2.4 /

't17' 2* 4 4 'open' 12 0.0 0.76 0. -2.4 /

```

/

-- well PI derived from welltest data

welpi

    't17'    10.5 /

/

--rptsched

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

--          +lay          ed conv

-- 0 0 0 0 0 0 2 0 2 0 0 0 2 0 /

-----

include

    'sched/JAN92.SCH' /

--rptsched

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

--          +lay          ed conv

-- 0 0 0 0 0 0 0 0 0 0 0 0 0 0 /

compdat

    't13' 2* 5 5 'shut' 16 0.0 0.76    0. -0.3 / --Later PLT shows no flow fro

/

welopen

    't03' 'open' /

    't04' 'open' /

```

```

        't07' 'shut' 0 0 0 /
        't08' 'open' /
        't13' 'open' /
        't16' 'open' /
    /
    dates
    7 'jan' 1992 /
    /
    welopen
        't05' 'open' /
        't02' 'open' /
    /

    compdat
        't02' 2* 1 1 'open' 12 0.0 0.76 0. -1.9 /
        't02' 2* 2 2 'open' 11 0.0 0.76 0. -1.9 /
        't02' 2* 3 3 'open' 15 0.0 0.76 0. -1.9 /
        't02' 2* 4 5 'open' 18 0.0 0.76 0. -1.9 /
    /
    -- well PI from welltest data
    welpi
        't02' 6.55 /
    /

    dates
    19 'jan' 1992 /
    /
    welopen

```

't16' 'shut' /

/

dates

21 'jan' 1992 /

/

--reduce time steps during pbu

tuning

1. 10. /

/

/

welopen

't03' 'shut' /

/

-- t18 RFT

--rptsched

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

-- +lay ed conv

-- 0 0 0 0 0 0 2 0 0 0 0 0 0 0 /

dates

25 'jan' 1992 /

/

-- MPLT t17

--rptsched

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

-- +lay ed conv

-- 0 0 0 0 0 0 0 0 2 0 0 0 0 0 /

```

-----

include

    'sched/FEB92.SCH' /

--rptsched

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

--          +lay          ed conv

-- 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 /

dates

    12 'feb' 1992 /

/

--reduce time steps during pbu

tuning

    1. 10. /

/

/

welopen

    't03' 'open' /

    't16' 'open' /

    't18' 'open' /

/

compdat

    't18' 2* 2 11 'open' 0 0.0 0.76 0. 0.9 /

/

-- well pi

```


welpi

't18' 4.39 /

/

dates

17 'feb' 1992 /

/

welopen

't14' 'open' /

/

compdat

't14' 2* 1 1 'open' 10 0.0 0.76 0. -2.2 /

't14' 2* 2 4 'open' 12 0.0 0.76 0. -2.2 /

't14' 2* 5 10 'open' 0 0.0 0.76 0. 30.0 /

/

-- well pi derived from welltest data

--welpi

-- 't14' 12.7 /

--/

include

'sched/MAR92.SCH' /

dates

3 'mar' 1992 /

/

--reduce time steps during pbu

tuning

1. 10. /

/

/

welopen

't03' 'shut' /

't08' 'shut' /

/

dates

4 'mar' 1992 /

/

--reduce time steps during pbu

welopen

't17' 'shut' /

/

include

'sched/APR92.SCH' /

dates

20 'apr' 1992 /

/

--reduce time steps during pbu

tuning

1. 10. /

/

/

welopen

't01' 'shut' /

't02' 'shut' /

't03' 'open' /

't08' 'open' /

't17' 'open' /

't19' 'open' /

/

compdat

't19' 2* 1 1 'open' 12 0.0 0.76 0. 2.8 /

't19' 2* 2 2 'open' 13 0.0 0.76 0. 2.8 /

't19' 2* 3 3 'open' 12 0.0 0.76 0. 2.8 /

't19' 2* 4 4 'open' 11 0.0 0.76 0. 2.8 /

/

--

welpi

't19' 8.99 /

/

dates

21 'apr' 1992 /

/

welopen

't04' 'shut' /

/

dates

23 'apr' 1992 /

/

welopen

't15' 'shut' /

/

include

'sched/MAY92.SCH' /

dates

5 'May' 1992 /

/

welopen

't01' 'open' /

't02' 'open' /

't04' 'open' /

't15' 'open' /

/

-- t20 RFT

--rptsched

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

-- +lay ed conv

-- 0 0 0 0 0 0 2 0 0 0 0 0 0 0 /

dates

10 'may' 1992 /

/

-- MPLT t14

--rptsched

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

-- +lay ed conv

-- 0 0 0 0 0 0 0 0 2 0 0 0 0 0 /

dates

13 'may' 1992 /

/

--reduce time steps during pbu

tuning

1. 10. /

/

/

welopen

't13' 'shut' /

't14' 'shut' /

't15' 'shut' /

't16' 'shut' /

/

--rptsched

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

-- +lay ed conv

-- 0 0 0 0 0 0 0 0 0 0 0 0 0 0 /

dates

29 'may' 1992 /

/

welopen

't20' 'open' /

/

compdat

't20' 2* 1 1 'open' 13 0.0 0.76 0. -2.1 /

't20' 2* 2 2 'open' 12 0.0 0.76 0. -2.1 /

't20' 2* 3 3 'open' 14 0.0 0.76 0. -2.1 /

/

--

welpi

't20' 6.03 /

/

include

'sched/JUN92.SCH' /

DATES

5 'JUN' 1992 /

/

welopen

't13' 'open' /

```

        't15' 'open' /

        't16' 'open' /

/

-----

include

    'sched/JUL92.SCH' /

dates

    25 'jul' 1992 /

/

--reduce time steps during pbu

tuning

    1. 10. /

/

/

welopen

    't10' 'shut' /

/

-- MPLT t18

--rptsched

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

--          +lay          ed conv

-- 0 0 0 0 0 0 2 0 2 0 0 0 0 0 /

-----

include

    'sched/AUG92.SCH' /

```

```
--rptsched
```

```
--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new
```

```
--          +lay          ed conv
```

```
-- 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 /
```

```
compdat
```

```
't14' 2* 5 10 'open' 0 0.0 0.76 0. 5.0 /
```

```
/
```

```
dates
```

```
13 'aug' 1992 /
```

```
/
```

```
welopen
```

```
't10' 'open' /
```

```
/
```

```
dates
```

```
23 'aug' 1992 /
```

```
/
```

```
welopen
```

```
't14' 'open' /
```

```
/
```

```
dates
```

```
25 'aug' 1992 /
```

```
/
```

```
welopen
```

```
't14' 'shut' /
```

```
/
```

```
-----  
include
```


'sched/SEP92.SCH' /

--welpi

-- 't01' 14.6 /

-- 't04' 8.0 /

-- 't05' 11.8 /

--/

dates

10 'sep' 1992 /

/

welopen

't16' 'shut' /

't17' 'shut' /

/

--reduce time steps during pbu

tuning

1. 10. /

/

/

dates

22 'sep' 1992 /

/

welopen

't16' 'open' /

't17' 'open' /

/

include

'sched/OCT92.SCH' /

dates

6 'oct' 1992 /

/

weltarg

'T03' 'ORAT' 2466 /

'T04' 'ORAT' 2500 /

/

dates

8 'oct' 1992 /

/

welopen

't03' 'shut' /

't04' 'shut' /

/

--reduce time steps during pbu

tuning

1. 10. /

/

/

dates

27 'oct' 1992 /

/

welopen

't03' 'open' /

't04' 'open' /

/

weltarg

'T03' 'ORAT' 3383 /

'T04' 'ORAT' 4096 /

/

include

'sched/NOV92.SCH' /

dates

13 'nov' 1992 /

/

welopen

't13' 'shut' /

't20' 'shut' /

/

--reduce time steps during pbu

tuning

```

1. 10. /

/

/

-----

include

'sched/DEC92.SCH' /

-----

welopen

't14' 'open' /

/

dates

11 'dec' 1992 /

/

welopen

't13' 'open' /

't20' 'open' /

/

--rptsched

--1 2 3 4 5 6 7 8 9 10 11 12 13 14 15

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

--          +lay          ed conv

-- 0 0 0 0 0 0 2 2 2 0 0 0 2 0 /

-----

-----

include

```

```
'sched/JAN93.SCH' /

--rptsched
--1 2 3 4 5 6 7 8 9 10 11 12 13 14 15
--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new
--          +lay          ed conv
-- 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 /
```

include

```
'sched/FEB93.SCH' /
```

include

```
'sched/MAR93.SCH' /
```

dates

```
13 'mar' 1993 /
```

```
/
```

--reduce time steps during pbu

tuning

1. 10. /

/

/

welopen

't01' 'shut' /

't02' 'shut' /

't03' 'shut' /

't04' 'shut' /

't05' 'shut' /

't08' 'shut' /

't10' 'shut' /

't13' 'shut' /

't14' 'shut' /

't15' 'shut' /

't16' 'shut' /

't17' 'shut' /

't19' 'shut' /

't20' 'shut' /

't11' 'shut' /

't12' 'shut' /

't18' 'shut' /

/

include

'sched/APR93.SCH' /

welopen

't01' 'open' /

't02' 'open' /

't03' 'open' /

't04' 'open' /

't05' 'open' /

't08' 'open' /

't10' 'open' /

't13' 'open' /

't14' 'open' /

't15' 'open' /

't17' 'open' /

't19' 'open' /

't20' 'open' /

't11' 'open' /

't12' 'open' /

't18' 'open' /

/

dates

23 'apr' 1993 /

/

welopen

't16' 'open' /

/

include

```

'sched/MAY93.SCH' /

-----

--T8 Layer A starts to scale up

compdat

't08' 2* 1 1 'shut' 13 0.0 0.76 0. -2.0 /

't14' 2* 5 10 'open' 0 0.0 0.76 0. 8.0 /

/

welpi

't08' 6.5 /

/

--rptsched

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

--          +lay          ed conv

-- 0 0 0 0 0 0 2 0 2 0 0 0 0 0 /

-----

include

'sched/JUN93.SCH' /

-----

--rptsched

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

--          +lay          ed conv

-- 0 0 1 0 0 0 0 0 0 0 0 0 0 0 /

```

include

'sched/JUL93.SCH' /

include

'sched/AUG93.SCH' /

--change to gas lift tables

-- well open ctl oil wat gas liq res bhp thp tab alq

wconprod

't14' 'open' 'orat' 3167 1* 1* 1* 1* 1500 1* 3 1* /

't17' 'open' 'orat' 2652 1* 1* 1* 1* 1500 1* 4 1* /

/

include

'sched/SEP93.SCH' /

include

'sched/OCT93.SCH' /

--***Change to gas lift table

-- well open ctl oil wat gas liq res bhp thp tab alq

wconprod

't05' 'open' 'orat' 3149 1* 1* 1* 1* 1500 1* 4 1* /

/

include

'sched/NOV93.SCH' /

compdat

't14' 2* 5 10 'open' 0 0.0 0.76 0.100. /

/

include

'sched/DEC93.SCH' /

--Change to gas lift tables

-- well open ctl oil wat gas liq res bhp thp tab alq

wconprod

't16' 'open' 'orat' 2895 1* 1* 1* 1* 1500 1* 3 1* /

't20' 'open' 'orat' 4292 1* 1* 1* 1* 1500 1* 3 1* /

/

--rptsched

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

-- +lay ed conv

-- 0 0 0 0 0 0 2 2 2 0 0 0 2 0 /

include

'sched/JAN94.SCH' /

--rptsched

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new

-- +lay ed conv

-- 0 0 0 0 0 0 0 0 0 0 0 0 0 0 /

include

'sched/FEB94.SCH' /

include

'sched/MAR94.SCH' /

-- Gas Lift for T4

-- well open ctl oil wat gas liq res bhp thp tab alq

wconprod

't04' 'open' 'orat' 2254 1* 1* 1* 1* 1500 1* 4 1* /

/

include

'sched/APR94.SCH' /

include

'sched/MAY94.SCH' /

--*****Put into MAY94.SCH file

-- well open ctl oil wat gas liq res bhp thp tab alq

--wconprod

```
-- 't01' 'open' 'orat' 4907 1* 1* 1* 1* 1500 1* 2 1* /
-- 't02' 'open' 'orat' 1966 1* 1* 1* 1* 1500 1* 2 1* /
-- 't03' 'open' 'orat' 3898 1* 1* 1* 1* 1500 1* 2 1* /
-- 't04' 'open' 'orat' 1725 1* 1* 1* 1* 1500 1* 4 1* /
-- 't05' 'open' 'orat' 3041 1* 1* 1* 1* 1500 1* 4 1* /
-- 't08' 'open' 'orat' 2934 1* 1* 1* 1* 1500 1* 2 1* /
-- 't10' 'open' 'orat' 2297 1* 1* 1* 1* 1500 1* 3 1* /
-- 't13' 'open' 'orat' 2098 1* 1* 1* 1* 1500 1* 4 1* /
-- 't14' 'open' 'orat' 3254 1* 1* 1* 1* 1500 1* 3 1* /
-- 't15' 'open' 'orat' 2147 1* 1* 1* 1* 1500 1* 3 1* /
-- 't16' 'open' 'orat' 2086 1* 1* 1* 1* 1500 1* 3 1* /
-- 't17' 'open' 'orat' 3148 1* 1* 1* 1* 1500 1* 4 1* /
-- 't19' 'open' 'orat' 3362 1* 1* 1* 1* 1500 1* 1 1* /
-- 't20' 'open' 'orat' 3584 1* 1* 1* 1* 1500 1* 3 1* /
--/
```

```
-----
include
```

```
'sched/JUN94.SCH' /
```

```
-----
include
```

```
'sched/JUL94.SCH' /
```

include

'sched/AUG94.SCH' /

compdat

't14' 2* 5 10 'open' 0 0.0 0.76 0.500. /

/

welpi

't14' 12.7 /

/

dates

01 'sep' 1994 /

/

--reduce time steps during pbu

tuning

1. 10. /

/

/

welopen

't01' 'shut' /

't02' 'shut' /

't03' 'shut' /

't04' 'shut' /

't05' 'shut' /

't08' 'shut' /

't10' 'shut' /

't13' 'shut' /

't14' 'shut' /

't15' 'shut' /

't16' 'shut' /

't17' 'shut' /

't19' 'shut' /

't20' 'shut' /

't11' 'shut' /

't12' 'shut' /

't18' 'shut' /

/

include

'sched/SEP94.SCH' /

welopen

't01' 'open' /

't02' 'open' /

't03' 'open' /

't04' 'open' /

't05' 'open' /

't08' 'open' /

't10' 'open' /

't13' 'open' /

't14' 'open' /

't15' 'open' /

't16' 'open' /

't17' 'open' /

't19' 'open' /

't20' 'open' /

't11' 'open' /

't12' 'open' /

't18' 'open' /

/

include

'sched/OCT94.SCH' /

include

'sched/NOV94.SCH' /

--T8 and T5 Reperforated

compdat

't08' 2* 1 1 'open' 11 0.0 0.76 0. -2.0 /

't05' 2* 6 6 'open' 15 0.0 0.76 0. -2.8 /

't05' 2* 7 7 'open' 14 0.0 0.76 0. -2.8 /

/

welpi

't08' 8.0 /

/

include

'sched/DEC94.SCH' /

include

'sched/JAN95.SCH' /

noecho

-- Well T01 Nat Flow, Table 1

include

'vfp/T01NF.VFP' /

-- Well T02 Nat Flow, Table 2

include

'vfp/T02NF.VFP' /

-- Well T03 Nat Flow, Table 3

include

'vfp/T03NF.VFP' /

-- Well T04 Nat Flow, Table 4

include

'vfp/T04NF.VFP' /

-- Well T05 Nat Flow, Table 5

include

'vfp/T05NF.VFP' /

-- Well T08 Nat Flow, Table 6

include

'vfp/T08NF.VFP' /

-- Well T10 Nat Flow, Table 7

include

'vfp/T10NF.VFP' /

-- Well T13 Nat Flow, Table 8

include

'vfp/T13NF.VFP' /

-- Well T14 Nat Flow, Table 9

include

'vfp/T14NF.VFP' /

-- Well T15 Nat Flow, Table 10

include

'vfp/T15NF.VFP' /

-- Well T16 Nat Flow, Table 11

include

'vfp/T16NF.VFP' /

-- Well T17 Nat Flow, Table 12

include

'vfp/T17NF.VFP' /

-- Well T19 Nat Flow, Table 13

include

'vfp/T19NF.VFP' /

-- Well T20 Nat Flow, Table 14

include

'vfp/T20NF.VFP' /

-- Well T01 Gas Lift (1 comp), Table 15

include

'vfp/T01GLL.VFP' /

-- Well T02 Gas Lift (1 comp), Table 16

include

'vfp/T02GLL.VFP' /

-- Well T03 Gas Lift (1 comp), Table 17

include

'vfp/T03GLL.VFP' /

-- Well T04 Gas Lift (1 comp), Table 18

include

'vfp/T04GLL.VFP' /

-- Well T05 Gas Lift (1 comp), Table 19

include

'vfp/T05GLL.VFP' /

-- Well T08 Gas Lift (1 comp), Table 20

include

'vfp/T08GLL.VFP' /

-- Well T10 Gas Lift (1 comp), Table 21

include

'vfp/T10GLL.VFP' /

-- Well T13 Gas Lift (1 comp), Table 22

include

'vfp/T13GLL.VFP' /

-- Well T14 Gas Lift (1 comp), Table 23

include

'vfp/T14GLL.VFP' /

-- Well T15 Gas Lift (1 comp), Table 24

include

'vfp/T15GLL.VFP' /

-- Well T16 Gas Lift (1 comp), Table 25

include

'vfp/T16GLL.VFP' /

-- Well T17 Gas Lift (1 comp), Table 26

include

'vfp/T17GLL.VFP' /

-- Well T19 Gas Lift (1 comp), Table 27

include

'vfp/T19GLL.VFP' /

-- Well T20 Gas Lift (1 comp), Table 28

include

'vfp/T20GLL.VFP' /

-- injector

include

'vfp/T11Z.VFP' /

include

'vfp/T12.VFP' /

include

'vfp/T18.VFP' /

echo

-- well open ctl oil wat gas liq res BHP thp tab alq

wconprod

't01' 'open' 'orat' 3020 1* 1* 1* 1* 500 1* 15 1* /

't02' 'open' 'orat' 1504 1* 1* 1* 1* 500 1* 16 1* /

't03' 'open' 'orat' 4754 1* 1* 1* 1* 500 1* 17 1* /

't04' 'shut' 'orat' 0 1* 1* 1* 1* 500 1* 18 1* /

't05' 'open' 'orat' 4288 1* 1* 1* 1* 500 1* 19 1* /

't08' 'open' 'orat' 2278 1* 1* 1* 1* 500 1* 6 1* /

't10' 'open' 'orat' 1961 1* 1* 1* 1* 500 1* 21 1* /

't13' 'open' 'orat' 1547 1* 1* 1* 1* 10 1* 22 1* /

't14' 'open' 'orat' 3956 1* 1* 1* 1* 500 1* 23 1* /

't15' 'open' 'orat' 4195 1* 1* 1* 1* 10 1* 24 1* /

't16' 'open' 'orat' 1903 1* 1* 1* 1* 500 1* 25 1* /

't17' 'open' 'orat' 1550 1* 1* 1* 1* 500 1* 26 1* /

't19' 'open' 'orat' 3931 1* 1* 1* 1* 500 1* 27 1* /

't20' 'open' 'orat' 2001 1* 1* 1* 1* 10 1* 28 1* /

/

compdat

't14' 2* 5 10 'shut' 0 0.0 0.76 0.500. /

/

include

'sched/FEB95.SCH' /

include

'sched/MAR95.SCH' /

include

'sched/APR95.SCH' /

include

'sched/MAY95.SCH' /

welpi

't01' 5.9 / --test 5/95 bhp>2000

-- 't02' 5.4 /

't03' 11.9 / --test 3/95 bhp>2000

-- 't04' 8.5 /

```
-- 't05' 10.8 /  
-- 't08' 6.5 /  
  't10' 3.7 / --test 5/95 bhp 1450  
  't13' 3.0 / --test 2/95 bhp 1750  
-- 't14' 13.1 /  
  't15' 7.6 / --test 5/95 bhp>2000  
  't16' 4.5 / --test 5/95 bhp 1750  
-- 't17' 6.4 /  
-- 't19' 9.0 /  
  't20' 5.3 / --test 5/95 bhp 1500  
/  
-----
```

```
include
```

```
  'sched/JUN95.SCH' /  
  
-----  
-----
```

```
include
```

```
  'sched/JUL95.SCH' /  
  
-----
```

```
-- All wells drawn down to 1750 psi  
-----
```

```
include
```

```
  'sched/AUG95.SCH' /
```

compdat

't12' 2* 1 1 'open' 0 0.0 0.76 0. -4.3 /

't12' 2* 2 8 'open' 0 0.0 0.76 0. 2.0 /

't11' 2* 1 5 'open' 0 0.0 0.76 0. -4.0/ --Assume top layers break down

't18' 2* 2 5 'open' 0 0.0 0.76 0. -2.0 / --Top layers -ve skin above fr

/

welphi

't11' 11.9 / --to match I.I. above frac P

't12' 12.0 / --to match I.I. above frac P (20)

't18' 10.0 / --to give higher I.I. above frac P

/

wconinj

't11' 'water' 'open' 'rate' 13120 1* 1* 'none' 6000 2500 1 /

't12' 'water' 'open' 'rate' 12392 1* 1* 'none' 6000 2500 2 /

't18' 'water' 'open' 'rate' 9585 1* 1* 'none' 6000 2500 3 /

/

--T04 3.5" coiled tubing straddle repairs holes in tubing

welopen

't04' 'open' /

/

include

'sched/SEP95.SCH' /

include

'sched/OCT95.SCH' /

include

'sched/NOV95.SCH' /

--welpi

-- 't02' 2.9 / --test 11/95

-- 't03' 7.2 / --test 11/95 bhp<2000 - just

-- 't04' 4.8 / --test 11/95

-- 't08' 3.8 / --test 3/94

-- 't14' 9.1 / --test 11/95

-- 't17' 4.1 / --test 11/95

--/

--T01 Coiled tubing millout of scale limited success

include

'sched/DEC95.SCH' /

include

'sched/JAN96.SCH' /

dates

14 'JAN' 1996 /

/

welopen

't17' 'shut' /

/

include

'sched/FEB96.SCH' /

include

'sched/MAR96.SCH' /

--includes 5 day platform S/D, T1 stays S/I

--includes T20 S/I to 20/3

include

'sched/APR96.SCH' /

include

'sched/MAY96.SCH' /

include

'sched/JUN96.SCH' /

--includes t01 open

welpi

't13' 3.0 / --test 2/95 bhp 1750

't15' 7.6 /

/

include

'sched/JUL96.SCH' /

include

'sched/AUG96.SCH' /

include

'sched/SEP96.SCH' /

dates

14 'SEP' 1996 /

/

welopen

't01' 'shut' /

't02' 'shut' /

't03' 'shut' /

't04' 'shut' /

't05' 'shut' /

't08' 'shut' /

't10' 'shut' /

't13' 'shut' /

't14' 'shut' /

't15' 'shut' /

't16' 'shut' /

't17' 'shut' /

't19' 'shut' /

't20' 'shut' /

't11' 'shut' /

't12' 'shut' /

't18' 'shut' /

/

dates

20 'SEP' 1996 /

/

welopen

't01' 'open' /

't02' 'open' /

't03' 'open' /

't04' 'open' /

't05' 'open' /

't08' 'open' /

't10' 'open' /

't13' 'open' /

't14' 'open' /

't15' 'open' /

't16' 'open' /

't17' 'open' /

't19' 'open' /

't20' 'open' /

't11' 'open' /

't12' 'open' /

't18' 'open' /

/

include

'sched/OCT96.SCH' /

include

'sched/NOV96.SCH' /

include

'sched/DEC96.SCH' /

include

'sched/JAN97.SCH' /

include

'sched/FEB97.SCH' /

include

'sched/MAR97.SCH' /

include

'sched/APR97.SCH' /

include

'sched/MAY97.SCH' /

include

'sched/JUN97.SCH' /

include

'sched/JUL97.SCH' /

compdat

't05' 2* 1 1 'shut' 10 0.0 0.76 1609. -2.8 /
't05' 2* 2 2 'shut' 11 0.0 0.76 261. -2.8 /
-- 't05' 2* 3 3 'open' 10 0.0 0.76 1566. -2.8 /
-- 't05' 2* 4 4 'open' 12 0.0 0.76 914. -2.8 /
/
/

include

'sched/AUG97.SCH' /

include


```
'sched/SEP97.SCH' /  
include  
    'sched/OCT97.SCH' /  
include  
    'sched/NOV97.SCH' /  
include  
    'sched/DEC97.SCH' /  
  
include  
    'sched/JAN98.SCH' /  
  
include  
    'sched/FEB98.SCH' /  
include  
    'sched/MAR98.SCH' /  
include  
    'sched/APR98.SCH' /  
include  
    'sched/MAY98.SCH' /  
include  
    'sched/JUN98.SCH' /  
include  
    'sched/JUL98.SCH' /  
dates  
19 'JUL' 1998 /  
/  
tuning  
1. 10. /
```

/

/

welopen

't01' 'shut' /

't02' 'shut' /

't03' 'shut' /

't04' 'shut' /

't05' 'shut' /

't08' 'shut' /

't10' 'shut' /

't13' 'shut' /

't14' 'shut' /

't15' 'shut' /

't16' 'shut' /

't17' 'shut' /

't19' 'shut' /

't20' 'shut' /

't11' 'shut' /

't12' 'shut' /

't18' 'shut' /

/

dates

1 'AUG' 1998 /

/

--reduce time steps during pbu

tuning

1. 10. /

/

/

dates

5 'AUG' 1998 /

/

welopen

't02' 'open' /

't03' 'open' /

't04' 'open' /

't05' 'open' /

't08' 'open' /

't13' 'shut' /

't14' 'open' /

't15' 'open' /

't16' 'open' /

't17' 'open' /

't19' 'open' /

't20' 'open' /

't01l' 'shut' /

't10l' 'shut' /

't11' 'open' /

't12' 'open' /

't18' 'open' /

/

compdat

't01l' 2* 1 9 'open' 0 0.0 0.76 0. -1.8 /

't10l' 2* 1 8 'open' 0 0.0 0.76 0. -2.3 /

/

include

'sched/AUG98.SCH' /

dates

1 'SEP' 1998 /

/

wconinj

't01l' 'water' 'open' 'rate' 13801 1* 1* 'none' 7500 1* 1 /

't10l' 'water' 'open' 'rate' 11242 1* 1* 'none' 7500 1* 1 /

/

welopen

't01l' 'open' /

't10l' 'open' /

/

include

'sched/SEP98.SCH' /

include

'sched/OCT98.SCH' /

include

'sched/NOV98.SCH' /

include

'sched/DEC98.SCH' /

include

'sched/JAN99.SCH' /

dates

01 'FEB' 1999 /

/

--reduce time steps during pbu

tuning

1. 10. /

/

/

welopen

't02' 'shut' /

't03' 'shut' /

't04' 'shut' /

't05' 'shut' /

't08' 'shut' /

't13' 'shut' /

't14' 'shut' /

't15' 'shut' /

't16' 'shut' /

't17' 'shut' /

't19' 'shut' /

't20' 'shut' /

't01l' 'shut' /

't10l' 'shut' /

't11' 'shut' /

't12' 'shut' /

't18' 'shut' /

/

dates

3 'FEB' 1999 /

/

--reduce time steps during pbu

tuning

1. 10. /

/

/

welopen

't02' 'open' /

't03' 'open' /

't04' 'open' /

't05' 'open' /

't08' 'open' /

't13' 'shut' /

't14' 'open' /

't15' 'open' /

't16' 'open' /

't17' 'open' /

't19' 'open' /

't20' 'open' /

't01l' 'open' /

't10l' 'open' /

't11' 'open' /

't12' 'open' /

't18' 'open' /

/

include

'sched/FEB99.SCH' /

dates

1 'MAR' 1999 /

/

```

--Start transition to prediction here

--Assumptions as for ARB18-45C but

--assume 1 compressor operation for checking lift curves

-- gconprod

-- 'field' 'orat' 70000 3* 'rate' /

--/

--gconinje

-- 'FIELD' 'WATER' 'RATE' 70000. /

--/

--    well open  ctl  oil wat gas liq res BHP  thp tab alq

wconprod

--    't01' 'open' 'thp' 1* 1* 1* 1* 1* 1000 150 15 1* /
      't02' 'open' 'thp' 1* 1* 1* 1* 1* 1000 150 16 1* /
      't03' 'open' 'thp' 1* 1* 1* 1* 1* 1000 150 17 1* /
      't04' 'open' 'thp' 1* 1* 1* 1* 1* 1000 150 18 1* /
      't05' 'open' 'thp' 1* 1* 1* 1* 1* 1000 150 19 1* /
      't08' 'open' 'thp' 3700 1* 1* 1* 1* 1000 150 6 1* /
      't14' 'open' 'thp' 1* 1* 1* 1* 1* 1000 150 23 1* /
      't15' 'open' 'thp' 1* 1* 1* 1* 1* 1000 150 24 1* /
      't16' 'open' 'thp' 1* 1* 1* 1* 1* 1000 150 25 1* /
      't17' 'open' 'thp' 1* 1* 1* 1* 1* 1000 150 26 1* /
      't19' 'open' 'thp' 1* 1* 1* 1* 1* 1000 150 27 1* /
      't20' 'open' 'thp' 1* 1* 1* 1* 1* 1000 150 28 1* /

/

wconinj

      't10i' 'water' 'open' 'thp' 12000 1* 1* 'none' 6000 2000 1 /
      't01i' 'water' 'open' 'thp' 12000 1* 1* 'none' 6000 2000 1 /
      't11i' 'water' 'open' 'thp' 14000 1* 1* 'none' 6000 2000 1 /

```

't12' 'water' 'open' 'thp' 15000 1* 1* 'none' 6000 2000 2 /

't18' 'water' 'open' 'thp' 12000 1* 1* 'none' 6000 2000 3 /

/

wefac

't*' 0.80 /

't11' 0.80 /

't12' 0.80 /

't18' 0.80 /

't01i' 0.80 /

't10i' 0.80 /

/

wvfpdp

't01' -55. /

't02' -400. /

't03' -700. /

't04' 300. /

't05' -90. /

't08' 0. /

't14' -430 /

't15' -300. /

't16' -75. /

't17' -1000. /

't19' -90. /

't20' -400. /

/

--rptsched --NEW

--p0 so sw sg rs rs gra fip wel vlp sum cpu aqu sch new


```
--          +lay          ed conv
-- 'PRES' 'SOIL' 'SWAT' 'SGAS' 'RS' 'RV' 'RESTART' /
--dates
-- 1 'JUL' 1999 /
--/
```

include

'pred-1000-10years.sched' /

End

Appendix B Java Code

1-Infill well Drilling

```

import java.awt.*;
import java.awt.event.*;
import javax.swing.*;
import java.io.*;
import java.util.*;
import java.text.*;

import jxl.*;
import jxl.read.biff.BiffException;

import jxl.CellView;
import jxl.Workbook;
import jxl.WorkbookSettings;
import jxl.format.UnderlineStyle;
import jxl.write.Formula;
import jxl.write.Label;
import jxl.write.Number;
import jxl.write.WritableCellFormat;
import jxl.write.WritableFont;
import jxl.write.WritableSheet;
import jxl.write.WritableWorkbook;
import jxl.write.WriteException;
import jxl.write.biff.RowsExceededException;

public class InfillManager
{
    //ManagerGUI managerGUI;
    private Workbook waterWorkbook, infillWorkbook;
    private double oilPrice ; //
    private double IOP_cost; //
    private double WP_cost; //
    private double WI_cost; //
    private double WO_cost;    // well operating cost
    private double WC_cost;    // well capital cost

    private double OIOE;      //
    private double DR;        //
    private int numOfYear;    //
    private int startYear;    //

    public ArrayList<Integer> yearsList;
    private ArrayList<Integer> wellsList;

    WaterFlood waterflood;
    InfillWell infillWell;
    InfillModelOutput modelOutput;
    private DecimalFormat df;

    public InfillManager(Workbook waterWorkbook, Workbook
infillWorkbook)
    {
        df = new DecimalFormat("#.##");
        this.waterWorkbook = waterWorkbook;
    }

```

```

        this.infillWorkbook = infillWorkbook;

        modelOutput=new InfillModelOutput();

        createWaterFlood();
        createInfillWell();

        yearsList = new ArrayList<Integer>();
        wellsList = new ArrayList<Integer>();

        //numOfYears = 24;
        startYear = 0;
        oilPrice = 50;
        IOP_cost = 8;
        WP_cost = 2;
        WI_cost = 2;
        OIOE = 0;
        DR = 0.1;
    }

    public void createWaterFlood()
    {
        Sheet sheet = waterWorkbook.getSheet(0); // iam reading data
        from the sheet1
        int rowCount = sheet.getRows();
        waterflood = new WaterFlood();

        // read FOPT column
        for(int i=4;i<rowCount;i++)
        {
            Cell cFOPT = sheet.getCell(2,i);
            Cell cFWPT = sheet.getCell(3,i);
            Cell cFWIT = sheet.getCell(4,i);
            waterflood.addFOPT(Double.valueOf(cFOPT.getContents()));
            waterflood.addFWPT(Double.valueOf(cFWPT.getContents()));
            waterflood.addFWIT(Double.valueOf(cFWIT.getContents()));
        }
    }

    public void createInfillWell()
    {
        Sheet sheet = infillWorkbook.getSheet(0); // iam reading data
        from the sheet1
        infillWell = new InfillWell();
        int rowCount = sheet.getRows();
        // read FOPT column
        for(int i=4;i<rowCount;i++)
        {
            Cell cFOPT = sheet.getCell(2,i);
            Cell cFWPT = sheet.getCell(3,i);
            Cell cFWIT = sheet.getCell(4,i);
            infillWell.addFOPT(Double.valueOf(cFOPT.getContents()));
            infillWell.addFWPT(Double.valueOf(cFWPT.getContents()));
            infillWell.addFWIT(Double.valueOf(cFWIT.getContents()));
        }
    }

    /*! read wells file
    *
    */

```

```

    public void readWellsFile(String wellsFile)
    {
        String inputLine;
        String parts[];
        String delimiter = ",";
        //catch the "FileNotFoundException" exception by using try and
catch
        try{
            for read
                FileReader fin= new FileReader(wellsFile); // open file
                Scanner scanner =new Scanner(fin);
                inputLine = scanner.nextLine(); //do something with
this line
                parts= inputLine.split(delimiter);
                for(int i=0;i<numOfYears;i++){
                    wellsList.add(Integer.parseInt(parts[i]));
                }
            }
        catch(FileNotFoundException ex){
            System.err.println(" File not found: "+ wellsFile);
            System.exit(1);
        }
    }

    /*!
    *
    */

    public InfillModelOutput getOutput()
    {
        return this.modelOutput;
    }

    /*
    * starting polymer injection
    */

    public void setNumOfYears(int years){
        numOfYears = years;
    }
    public int getNumOfYears(){
        return this.numOfYears;
    }

    public void setYearsList(){
        int start = startYear - 1;
        for(int i=0;i<start;i++){
            yearsList.add(i,i-start);
        }
        for(int j = start; j < numOfYears; j++){
            int prev = yearsList.get(j-1);
            yearsList.add(j,prev+1);
        }
    }

    public void setStartYear(int startYear){
        this.startYear = startYear;
    }

    public int getStartYear(){
        return this.startYear;
    }
}

```

```

public ArrayList getYearsList()
{
    return yearsList;
}

/*
 * ste global variables
 */

    public void setOilPrice(double oilPrice){
        this.oilPrice = oilPrice;
    }
    public void setIOP_cost(double IOP_cost){
        this.IOP_cost = IOP_cost;
    }
    public void setWP_cost(double WP_cost){
        this.WP_cost = WP_cost;
    }
    public void setWI_cost(double WI_cost){
        this.WI_cost = WI_cost;
    }
    public void setWO_cost(double WO_cost){
        this.WO_cost = WO_cost;
    }
    public void setWC_cost(double WC_cost){
        this.WC_cost = WC_cost;
    }

    /*! Cost model operations
    *
    */

    /*! calculate incemental oil production
    *
    */
    public void doIOP()
    {
        modelOutput.clearIOP();
        for(int i=0 ; i<numOfYears;i++)
        {
            double iop = infillWell.getByIndexFOPT(i)-
waterflood.getByIndexFOPT(i);
            modelOutput.addIOP(iop);
        }
    }

    /*!
    *
    */
    public void doIWP()
    {
        modelOutput.clearIWP();
        for(int i=0 ; i<numOfYears;i++)
        {
            double iwp = infillWell.getByIndexFWPT(i)-
waterflood.getByIndexFWPT(i);
            modelOutput.addIWP(iwp);
        }
    }

```

```

    }

    public void doIWI ()
    {
        modelOutput.clearIWI ();
        for(int i=0 ; i<numOfYears;i++)
        {
            double iwi = infillWell.getByIndexFWIT(i) -
waterflood.getByIndexFWIT(i);
            modelOutput.addIWI(iwi);
        }
    }

    public void doRFOP ()
    {
        modelOutput.clearRFOP ();
        for(int i=0 ; i<numOfYears;i++)
        {
            double RFOP = modelOutput.getByIndexIOP(i)*oilPrice;
            modelOutput.addRFOP(RFOP);
        }
    }

    /*!
    *
    *
    */
    public void doIWDCE (ArrayList<Double> NumberOfNewWells)
    {
        modelOutput.clearIWDCE ();
        for(int i=0 ; i<numOfYears;i++)
        {
            double iwdce = -(NumberOfNewWells.get(i)*WC_cost);
            modelOutput.addIWDCE(iwdce);
        }
    }

    /*!
    *
    *
    */
    public void doIWOE (ArrayList<Double>
cumulativeNumberOfNewWellsList)
    {
        modelOutput.clearIWOE ();
        for(int i=0 ; i<numOfYears;i++)
        {
            double iwoe = -
(cumulativeNumberOfNewWellsList.get(i)*WO_cost);
            modelOutput.addIWOE(iwoe);
        }
    }

    /*!
    *
    *
    */
    public void doIWCE ()
    {
        modelOutput.clearIWCE ();
        for(int i=0 ; i<numOfYears;i++)

```

```

        {
            double iwce =
modelOutput.getByIndexIWDCE(i)+modelOutput.getByIndexIWOE(i);
            modelOutput.addIWCE(iwce);
        }
    }

    /*!
    *
    *
    */
    public void doCIWCE()
    {
        modelOutput.clearCIWCE();
        double CIWCE = 0;
        for(int i=0 ; i<numOfYears;i++)
        {
            CIWCE = CIWCE+modelOutput.getByIndexIWCE(i);
            modelOutput.addCIWCE(CIWCE);
        }
    }

    /*!
    *
    *
    */
    public void doIOPE()
    {
        modelOutput.clearIOPE();
        for(int i=0 ; i<numOfYears;i++)
        {
            double IOPE = -(modelOutput.getByIndexIOP(i)*IOP_cost);
            modelOutput.addIOPE(IOPE);
        }
    }

    /*!
    *
    *
    */
    public void doIWPE()
    {
        double iwpe;
        modelOutput.clearIWPE();
        for(int i=0 ; i<numOfYears;i++)
        {
            iwpe = -(modelOutput.getByIndexIWP(i)*WP_cost);
            modelOutput.addIWPE(iwpe);
        }
    }

    /*!
    *
    *
    */
    public void doIWIE()
    {
        double iwie;
        modelOutput.clearIWIE();
        for(int i=0 ; i<numOfYears;i++)
        {
            iwie = -(modelOutput.getByIndexIWI(i)*WI_cost);

```

```

        modelOutput.addIWIE(iwie);
    }
}

/*!
 *
 *
 */
public void doIOE(ArrayList<Double>
OtherIncrementalOperatingExpenses)
{
    modelOutput.clearIOE();
    for(int i=0 ; i<numOfYears;i++)
    {
        double IOE =
modelOutput.getByIndexIOPE(i)+modelOutput.getByIndexIWPE(i)+modelOutput
t.getByIndexIWIE(i)+OtherIncrementalOperatingExpenses.get(i);
        modelOutput.addIOE(IOE);
    }
}

/*!
 *
 *
 *
 */
public void doCIOE()
{
    modelOutput.clearCIOE();
    double CIOE = 0;
    for(int i=0 ; i<numOfYears;i++)
    {
        CIOE = CIOE+modelOutput.getByIndexIOE(i);
        modelOutput.addCIOE(CIOE);
    }
}

/*!
 *
 *
 *
 */
public void doICF()
{
    modelOutput.clearICF();
    for(int i=0 ; i<numOfYears;i++){
        double ICF =
modelOutput.getByIndexRFOP(i)+modelOutput.getByIndexIOE(i)+modelOutput
.getByIndexIWCE(i);
        modelOutput.addICF(ICF);
    }
}

public void doCICF()
{
    modelOutput.clearCICF();
    double CICF = 0;
    for(int i=0 ; i<numOfYears;i++)
    {
        CICF = CICF+modelOutput.getByIndexICF(i);
        modelOutput.addCICF(CICF);
    }
}

```



```

    }
}

public void doDCF()
{
    modelOutput.clearDCF();
    for(int i=0 ; i<numOfYears;i++)
    {
        double DCF = modelOutput.getByIndexICF(i)*Math.pow(1+DR,-
yearsList.get(i));
        modelOutput.addDCF(DCF);
    }
}

public void doCDCF()
{
    modelOutput.clearCDCF();
    double CDCF = 0;
    for(int i=0 ; i<numOfYears;i++)
    {
        CDCF = CDCF+modelOutput.getByIndexDCF(i);
        modelOutput.addCDCF(CDCF);
    }
}

public double doNPVI()
{
    double result;
    double lastCDCF = modelOutput.getByIndexCDCF(numOfYears-1);
    double min = modelOutput.getByIndexCDCF(1);
    for(int i=2 ; i<numOfYears ; i++)
        if(modelOutput.getByIndexCDCF(i)< min)
            min = modelOutput.getByIndexCDCF(i);
    result = -(lastCDCF/min);
    return result;
}

public String runApp(ArrayList<Double>
cumulativeNumberOfNewWellsList,ArrayList<Double>
NumberOfNewWells,ArrayList<Double> OtherIncrementalOperatingExpenses)
{
    doIOP(); //
    doIWP(); //
    doIWI(); //

    doRFOP(); //
    doIWDCE(NumberOfNewWells);
    doIWOE(cumulativeNumberOfNewWellsList);
    doIWCE();
    doCIWCE();
}

```

```

        doIOPE(); //

        doIWPE(); //

        doIWIE(); //

        doIOE(OtherIncrementalOperatingExpenses); //

        doCIOE(); //

        doICF(); //

        doCICF(); //

        doDCF(); //

        doCDCF(); //

        double npvi = doNPVI();
        String npv =
df.format(getOutput().getByIndexCDCF(getNumOfYears()-1));
        String mco =
df.format(getOutput().getByIndexCDCF(getNumOfYears()-1)/doNPVI());
        String ioe = modelOutput.getIOEDetails();
        String icf = modelOutput.getICFDetails();
        String dcf = modelOutput.getDCFDetails();
        String cdcf = modelOutput.getCDCFDetails();

        //String line = " \n\nCost Model output" + "\nIOE
        ,"+ioe+"\nICF ,"+icf+"\nNPV ,"+ npv + "\nNPVI ,"+ npvi + "\n";
        String line = ", "+dcf+cdcf+ npv+", " + npvi+", "+mco;

        return line;
    }

}

```

2-Polymer flooding

```

import java.awt.*;
import java.awt.event.*;
import javax.swing.*;
import java.io.*;
import java.util.*;
import java.text.*;

import jxl.*;
import jxl.read.biff.BiffException;

import jxl.CellView;
import jxl.Workbook;
import jxl.WorkbookSettings;
import jxl.format.UnderlineStyle;
import jxl.write.Formula;

```

```

import jxl.write.Label;
import jxl.write.Number;
import jxl.write.WritableCellFormat;
import jxl.write.WritableFont;
import jxl.write.WritableSheet;
import jxl.write.WritableWorkbook;
import jxl.write.WriteException;
import jxl.write.biff.RowsExceededException;

public class Manager
{
    //ManagerGUI managerGUI;
    private Workbook waterWorkbook, polymerWorkbook;
    private double polymerCost ;
    private double oilPrice ;
    private double IOP_cost;
    private double WP_cost;
    private double IPP_cost;
    private double IPI_cost;
    private double WI_cost;
    private double OIOE;
    private double DR;
    private int numOfYear;
    private int startYear;
    public ArrayList<Integer> yearsList;
    private ArrayList<Double> ICEList;
    WaterFlood waterflood;
    PolymerFlood polymerflood;
    PolymerModelOutput modelOutput;
    private DecimalFormat df;

    public Manager(Workbook waterWorkbook, Workbook polymerWorkbook)
    {
        df = new DecimalFormat("#.##");
        this.waterWorkbook = waterWorkbook;
        this.polymerWorkbook = polymerWorkbook;
        modelOutput=new PolymerModelOutput();
        createWaterFlood();
        createPolymerFlood();
        yearsList = new ArrayList<Integer>();
        ICEList = new ArrayList<Double>();
        //numOfYears = 24;
        startYear = 3;
        oilPrice = 50;
        polymerCost = 1.5;
        IOP_cost = 8;
        WP_cost = 2;
        IPP_cost = 0.5;
        IPI_cost = 0.5;
        WI_cost = 2;
        OIOE = 0;
        DR = 0.1;
    }

    public void createWaterFlood()
    {
        Sheet sheet = waterWorkbook.getSheet(0); // iam reading data
        from the sheet1
        int rowCount = sheet.getRows();
    }
}

```

```

        waterflood = new WaterFlood();

        // read FOPT column
        for(int i=4;i<rowCount;i++)
        {
            Cell cFOPT = sheet.getCell(2,i);
            Cell cFWPT = sheet.getCell(3,i);
            Cell cFWIT = sheet.getCell(4,i);
            waterflood.addFOPT(Double.valueOf(cFOPT.getContents()));
            waterflood.addFWPT(Double.valueOf(cFWPT.getContents()));
            waterflood.addFWIT(Double.valueOf(cFWIT.getContents()));
        }

    }

    public void createPolymerFlood()
    {
        Sheet sheet = polymerWorkbook.getSheet(0); // iam reading data
        from the sheet1
        polymerflood = new PolymerFlood();
        int rowCount = sheet.getRows();
        // read FOPT column
        for(int i=4;i<rowCount;i++)
        {
            Cell cFOPT = sheet.getCell(2,i);
            Cell cFWPT = sheet.getCell(3,i);
            Cell cFWIT = sheet.getCell(6,i);
            Cell cWCPT = sheet.getCell(4,i);
            Cell cWCIT = sheet.getCell(5,i);
            polymerflood.addFOPT(Double.valueOf(cFOPT.getContents()));
            polymerflood.addFWPT(Double.valueOf(cFWPT.getContents()));
            polymerflood.addFWIT(Double.valueOf(cFWIT.getContents()));
            polymerflood.addWCIT(Double.valueOf(cWCIT.getContents()));
            polymerflood.addWCPT(Double.valueOf(cWCPT.getContents()));
        }
    }

    /*
     * read ICE file
     */
    public boolean readICEfile(String ICEfile)
    {
        String inputLine;
        String parts[];
        String delimiter = ",";
        //catch the "FileNotFoundException" exception by using try and
        catch
        try{
            FileReader fin= new FileReader("./data/model-
            input/"+ICEfile); // open file for read
            Scanner scanner =new Scanner(fin);
            inputLine = scanner.nextLine(); //do something with
            this line
            parts= inputLine.split(delimiter);
            for(int i=0;i<numOfYears;i++){
                ICEList.add(Double.parseDouble(parts[i]));
            }
            return true;
        }
        catch(FileNotFoundException ex){

```

```

        //System.err.println(" File not found: "+ ICEfile+"\n");
        //System.exit(1);
        return false;
    }
}

public String getICEDetails() {
    String buff="";
    for(int i=0;i<numOfYears;i++)
        buff+=ICEList.get(i).toString()+"\n";
    return buff;
}

/*
 *
 */

public PolymerModelOutput getOutput()
{
    return this.modelOutput;
}

/*
 * starting polymer injection
 */

public void setNumOfYears(int years){
    numOfYears = years;
}

public int getNumOfYears() {
    return this.numOfYears;
}

public void setYearsList(){
    int start = startYear - 1;
    for(int i=0;i<start;i++)
        yearsList.add(i,i-start);
    for(int j = start; j <= numOfYears; j++){
        int prev = yearsList.get(j-1);
        yearsList.add(j,prev+1);
    }
}

public void setStartYear(int startYear){
    this.startYear = startYear;
}

public int getStartYear(){
    return this.startYear;
}

/*
 * ste global variables
 */
public void setPolymerCost(double polymerCost){
    this.polymerCost = polymerCost;
}

public void setOilPrice(double oilPrice){
    this.oilPrice = oilPrice;
}

public void setIOP_cost(double IOP_cost){

```

```

        this.IOP_cost = IOP_cost;
    }
    public void setWP_cost(double WP_cost){
        this.WP_cost = WP_cost;
    }
    public void setIPP_cost(double IPP_cost){
        this.IPP_cost = IPP_cost;
    }
    public void setIPI_cost(double IPI_cost){
        this.IPI_cost = IPI_cost;
    }
    public void setWI_cost(double WI_cost){
        this.WI_cost = WI_cost;
    }
}

/*
 * Cost model operations
 */
public void doIOP()
{
    modelOutput.clearIOP();
    for(int i=0 ; i<numOfYears;i++)
    {
        double iop = polymerflood.getByIndexFOPT(i) -
waterflood.getByIndexFOPT(i);
        modelOutput.addIOP(iop);
    }
}

public void doIWP()
{
    modelOutput.clearIWP();
    for(int i=0 ; i<numOfYears;i++)
    {
        double iwp = polymerflood.getByIndexFWPT(i) -
waterflood.getByIndexFWPT(i);
        modelOutput.addIWP(iwp);
    }
}

public void doIWI()
{
    modelOutput.clearIWI();
    for(int i=0 ; i<numOfYears;i++)
    {
        double iwi = polymerflood.getByIndexFWIT(i) -
waterflood.getByIndexFWIT(i);
        modelOutput.addIWI(iwi);
    }
}

public void doPPE()
{
    modelOutput.clearPPE();
    for(int i=0 ; i<numOfYears;i++)
    {
        double ppe = -
(polymerflood.getByIndexWCIT(i)*polymerCost);
        modelOutput.addPPE(ppe);
    }
}
}

```

```

public void doRFOP ()
{
    modelOutput.clearRFOP ();
    for(int i=0 ; i<numOfYears;i++)
    {
        double RFOP = modelOutput.getByIndexIOP(i)*oilPrice;
        modelOutput.addRFOP (RFOP) ;
    }
}

public void doIOPE ()
{
    modelOutput.clearIOPE ();
    for(int i=0 ; i<numOfYears;i++)
    {
        double IOPE = -(modelOutput.getByIndexIOP(i)*IOP_cost);
        modelOutput.addIOPE (IOPE) ;
    }
}

public void doIWIE ()
{
    double iwie,wcit;
    modelOutput.clearIWIE ();
    for(int i=0 ; i<numOfYears;i++)
    {
        wcit = polymerflood.getByIndexWCIT(i);
        if(wcit <= 0){
            iwie = -(modelOutput.getByIndexIWI(i)*WI_cost);
            modelOutput.addIWIE (iwie) ;
        }
        else{
            iwie = -(polymerflood.getByIndexFWIT(i)*(WI_cost +
IPI_cost)-waterflood.getByIndexFWIT(i)*WI_cost);
            modelOutput.addIWIE (iwie) ;
        }
    }
}

public void doIOE ()
{
    modelOutput.clearIOE ();
    for(int i=0 ; i<numOfYears;i++)
    {
        double IOE =
modelOutput.getByIndexPPE(i)+modelOutput.getByIndexIOPE(i)+modelOutput
.getByIndexIWPE(i)+modelOutput.getByIndexIWIE(i)+OIOE;
        modelOutput.addIOE (IOE) ;
    }
}

public void doIWPE ()
{
    double iwpe, wcpt;
    modelOutput.clearIWPE ();
    for(int i=0 ; i<numOfYears;i++)
    {
        wcpt = polymerflood.getByIndexWCPT(i);
        if(wcpt <= 0){

```

```

        iwpe = -(modelOutput.getByIndexIWP(i)*WP_cost);
        modelOutput.addIWPE(iwpe);
    }
    else{
        iwpe = -(polymerflood.getByIndexFWPT(i)*(WP_cost +
IPP_cost)-waterflood.getByIndexFWPT(i)*WP_cost);
        modelOutput.addIWPE(iwpe);
    }
}

public void doICF()
{
    modelOutput.clearICF();
    for(int i=0 ; i<numOfYears;i++)
    {
        double ICF =
modelOutput.getByIndexRFOP(i)+modelOutput.getByIndexIOE(i)+ICEList.get
(i);
        modelOutput.addICF(ICF);
    }
}

public void doCICF()
{
    modelOutput.clearCICF();
    double CICF = 0;
    for(int i=0 ; i<numOfYears;i++)
    {
        CICF = CICF+modelOutput.getByIndexICF(i);
        modelOutput.addCICF(CICF);
    }
}

public void doDCF()
{
    modelOutput.clearDCF();
    for(int i=0 ; i<numOfYears;i++)
    {
        double DCF = modelOutput.getByIndexICF(i)*Math.pow(1+DR,-
yearsList.get(i));
        modelOutput.addDCF(DCF);
    }
}

public void doCDCF()
{
    modelOutput.clearCDCF();
    double CDCF = 0;
    for(int i=0 ; i<numOfYears;i++)
    {
        CDCF = CDCF+modelOutput.getByIndexDCF(i);
        modelOutput.addCDCF(CDCF);
    }
}

public double doNPVI()
{

```



```

        double lastCDCF = modelOutput.getByIndexCDCF(numOfYears-1);
        double min = modelOutput.getByIndexCDCF(0);
        double result;
        for(int i=0 ; i<numOfYears ; i++)
            if(modelOutput.getByIndexCDCF(i)< min)
                min = modelOutput.getByIndexCDCF(i);
        result = -(lastCDCF/min);
        return result;
    }

    public String runApp()
    {
        doIOP();
        doIWP();
        doIWI();
        doPPE();
        doRFOP();
        doIOPE();
        doIWPE();
        doIWIE();
        doIOE();
        doICF();
        doCICF();
        doDCF();
        doCDCF();
        String npvi = df.format(doNPVI());
        String npv =
df.format(getOutput().getByIndexCDCF(getNumOfYears()-1));
        String mco =
df.format(getOutput().getByIndexCDCF(getNumOfYears()-1)/doNPVI());
        String ioe = modelOutput.getIOEDetails();
        String icf = modelOutput.getICFDetails();
        //String line = " \n\nCost Model output" + "\nIOE
        ,"+ioe+"\nICF ,"+icf+"\nNPV ,"+ npv + "\nNPVI ,"+ npvi + "\n";
        String line = ", "+ioe+icf+ npv+", "+ npvi+", "+mco;
        return line;
    }

    public PolymerModelOutput runApp2()
    {
        doIOP();
        doIWP();
        doIWI();
        doPPE();
        doRFOP();
        doIOPE();
        doIWPE();
        doIWIE();
        doIOE();
        doICF();
        doCICF();
        doDCF();
        doCDCF();
        return modelOutput;
    }
}

```

3-Incremental net present value

```

import java.awt.*;
import java.awt.event.*;
import javax.swing.*;
import java.io.*;
import java.util.*;

public class IncrementalNPV
{
    ManagerGUI gui;

    //infill data
    private ArrayList<Double> oilPriceList_infill;
    private ArrayList<Double> IOP_costList_infill;
    private ArrayList<Double> WI_costList_infill;
    private ArrayList<Double> WP_costList_infill;
    private ArrayList<Double> WO_costList_infill;
    private ArrayList<Double> WC_costList_infill;
    private ArrayList<Double> npv_infill;
    private ArrayList<Double> npvi_infill;
    private ArrayList<Double> mco_infill;

    //polymer data
    private ArrayList<Double> polymer_concentrationList;
    private ArrayList<Double> PF_polymer;
    private ArrayList<Double> oilPriceList_polymer;
    private ArrayList<Double> IOP_costList_polymer;
    private ArrayList<Double> WI_costList_polymer;
    private ArrayList<Double> WP_costList_polymer;
    private ArrayList<Double> PC_costList_polymer;
    private ArrayList<Double> IPP_costList_polymer;
    private ArrayList<Double> IPI_costList_polymer;
    private ArrayList<Double> npv_polymer;
    private ArrayList<Double> npvi_polymer;
    private ArrayList<Double> mco_polymer;

    public IncrementalNPV(ManagerGUI gui)
    {
        this.gui = gui;
        oilPriceList_infill = new ArrayList<Double>();
        WI_costList_infill = new ArrayList<Double>();
        IOP_costList_infill = new ArrayList<Double>();
        WP_costList_infill = new ArrayList<Double>();
        WO_costList_infill = new ArrayList<Double>();
        WC_costList_infill = new ArrayList<Double>();
        npv_infill = new ArrayList<Double>();
        npvi_infill = new ArrayList<Double>();
        mco_infill = new ArrayList<Double>();

        polymer_concentrationList = new ArrayList<Double>();
        PF_polymer = new ArrayList<Double>();
        oilPriceList_polymer = new ArrayList<Double>();
        WI_costList_polymer = new ArrayList<Double>();
        IOP_costList_polymer = new ArrayList<Double>();
        WP_costList_polymer = new ArrayList<Double>();
        PC_costList_polymer = new ArrayList<Double>();
        IPP_costList_polymer = new ArrayList<Double>();
        IPI_costList_polymer = new ArrayList<Double>();
        npv_polymer = new ArrayList<Double>();
        npvi_polymer = new ArrayList<Double>();
        mco_polymer = new ArrayList<Double>();
    }
}

```

```

    }

    public void run()
    {
        gui.displayArea.append("\n Incremental NPV Model");
        String infillFileName = getFileName(" Infill File");
        String polymerFileName = getFileName(" Polymer File");
        //String infillFileName = "../data/model-output/infill.txt";
        //String polymerFileName = "../data/model-output/polymer.txt";
        readInfillFile(infillFileName);
        readPolymerFile(polymerFileName);
        modelAnalysis();

    }

    public String getFileName(String title)
    {
        String fileName;
        try{
            fileName = gui.inputDialog(title);
            return fileName;
        }catch(IOException ex){
            return ex.getMessage();
        }
    }

    public void readInfillFile(String fileName)
    {
        String inputLine;
        String parts[];
        String delimiter = ",";
        try{
            FileReader fin= new FileReader(fileName);
            Scanner scanner =new Scanner(fin);
            inputLine = scanner.nextLine(); // read the first line
            inputLine = scanner.nextLine(); // read the second line
            gui.displayArea.append("\n Infill file > "+ inputLine);

            parts = inputLine.split(delimiter);
            gui.displayArea.append("\n Part[47] > "+ parts[47]);
            do
            {
                inputLine = scanner.nextLine();
                parts = inputLine.split(delimiter);
                oilPriceList_infill.add(Double.parseDouble(parts[1]));
                IOP_costList_infill.add(Double.parseDouble(parts[2]));
                WI_costList_infill.add(Double.parseDouble(parts[3]));
                WP_costList_infill.add(Double.parseDouble(parts[4]));
                WO_costList_infill.add(Double.parseDouble(parts[5]));
                WC_costList_infill.add(Double.parseDouble(parts[6]));
                npv_infill.add(Double.parseDouble(parts[47]));
                npvi_infill.add(Double.parseDouble(parts[48]));
                mco_infill.add(Double.parseDouble(parts[49]));
            }while(scanner.hasNext());
            gui.displayArea.append("\n Reading infill file ... Done
\n");
        }
        catch(FileNotFoundException ex){
            gui.displayArea.append(" File not found: "+ fileName);
        }
    }

    public void readPolymerFile(String fileName)

```

```

    {
        String inputLine;
        String parts[];
        String delimiter = ",";
        try{
            FileReader fin= new FileReader(fileName);
            Scanner scanner =new Scanner(fin);
            inputLine = scanner.nextLine(); // read the first line
            inputLine = scanner.nextLine(); // read the second line
            gui.displayArea.append("\n Polymer file > "+ inputLine);

            parts = inputLine.split(delimiter);
            gui.displayArea.append("\n Part[58] > "+ parts[58]);

            do
            {
                inputLine = scanner.nextLine();
                parts = inputLine.split(delimiter);

                polymer_concentrationList.add(Double.parseDouble(parts[0]));
                PF_polymer.add(Double.parseDouble(parts[2]));
                oilPriceList_polymer.add(Double.parseDouble(parts[3]));
                IOP_costList_polymer.add(Double.parseDouble(parts[4]));
                WI_costList_polymer.add(Double.parseDouble(parts[5]));
                WP_costList_polymer.add(Double.parseDouble(parts[6]));
                PC_costList_polymer.add(Double.parseDouble(parts[7]));
                IPP_costList_polymer.add(Double.parseDouble(parts[8]));
                IPI_costList_polymer.add(Double.parseDouble(parts[9]));
                npv_polymer.add(Double.parseDouble(parts[58]));
                npvi_polymer.add(Double.parseDouble(parts[59]));
                mco_polymer.add(Double.parseDouble(parts[60]));
            }while(scanner.hasNext());
            gui.displayArea.append("\n Reading polymer file ... Done
\n");
        }
        catch(FileNotFoundException ex){
            gui.displayArea.append(" File not found: "+ fileName);
        }
    }

    /*
    * run model analysis
    */
    public void modelAnalysis()
    {
        String str = getHeader();
        int count = 0;
        FileWriter fstream;
        BufferedWriter out;
        try{
            // Create file
            fstream = new FileWriter("./data/model-
output/incremental.txt");
            out = new BufferedWriter(fstream);

            for(int infill=0; infill<oilPriceList_infill.size();
infill++)
            {
                for(int polymer=0;
polymer<oilPriceList_polymer.size(); polymer++)
                {
                    if(oilPriceList_polymer.get(polymer).doubleValue()
== oilPriceList_infill.get(infill).doubleValue())

```

```

        &&
IOP_costList_polymer.get(polymer).doubleValue() ==
IOP_costList_infill.get(infill).doubleValue()
        &&
WI_costList_polymer.get(polymer).doubleValue() ==
WI_costList_infill.get(infill).doubleValue()
        &&
WP_costList_polymer.get(polymer).doubleValue() ==
WP_costList_infill.get(infill).doubleValue()
    {
        //String str = "\nPC,PF,Oil
Price,IOPC,WIC,IPPC,IPIC,Wo,WC,INPV";
        count++;

        double inpv =
npv_infill.get(infill).doubleValue() -
npv_polymer.get(polymer).doubleValue();
        double inpvi =
npvi_infill.get(infill).doubleValue() -
npvi_polymer.get(polymer).doubleValue();
        double imco =
mco_infill.get(infill).doubleValue() -
mco_polymer.get(polymer).doubleValue();

        str+="\n"
        +
polymer_concentrationList.get(polymer)
        + "," + PF_polymer.get(polymer)
        + "," +
oilPriceList_polymer.get(polymer)
        + "," +
IOP_costList_polymer.get(polymer)
        + "," +
WI_costList_polymer.get(polymer)
        + "," +
WP_costList_polymer.get(polymer)
        + "," +
PC_costList_polymer.get(polymer)
        + "," +
IPP_costList_polymer.get(polymer)
        + "," +
IPI_costList_polymer.get(polymer)
        + "," + WO_costList_infill.get(infill)
        + "," + WC_costList_infill.get(infill)
        + "," + inpv
        + "," + inpvi
        + "," + imco;
        gui.displayArea.append(str);
        out.write(str);
        str="";
    }
}

gui.displayArea.append(" \n count > " + count + "\n polymer
size > " + oilPriceList_polymer.size() + "\n infill size > " +
oilPriceList_infill.size());
out.close();
gui.displayArea.append("\n\n Cost Model Analysis ....
Done");
} catch (Exception e) { //Catch exception if any
    gui.displayArea.append("Error: " + e.getMessage());
}

```

```
    }

    public String getHeader(){
        String str = "\nPC,PF,Oil
Price,IOPC,WIC,WPC,PC,IPPC,IPIC,Wo,WC,INPV,INPVI,IMCO";
        return str;
    }

}
```

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